Exhibit 91

2015 Anadarko Investor Conference Call

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INVESTOR RELATIONS

John Colglazier
Senior Vice President
832/636-2306

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Preserving Value & Positioning for the Future

John Colglazier

March 3, 2015

Agenda

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	Presenter	Title
Strategic Overview	Al Walker	Chairman, President and CEO
Financial Discipline	Bob Gwin	EVP, Finance and CFO
U.S. Onshore	Chuck Meloy	EVP, U.S. Onshore Exploration and Production
International & Deepwater Operations	Jim Kleckner	EVP, International and Deepwater Operations
International & Deepwater Exploration	Bob Daniels	EVP, International and Deepwater Exploration
Closing Remarks	Al Walker	Chairman, President and CEO
Q&A	All	

Cautionary Language

Regarding Forward-Looking Statements and Other Matters

This presentation contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Anadarko believes that its expectations are based on reasonable assumptions. No assurance, however, can be given that such expectations will prove to have been correct. A number of factors could cause actual results to differ materially from the projections, anticipated results, or other expectations expressed in this presentation, including Anadarko's ability to meet financial and operating guidance, achieve its production targets, successfully manage its capital expenditures, consummate the transaction described in this presentation, timely complete and commercially operate the projects and drilling prospects identified in this presentation, achieve production and budget expectations on its mega projects, and successfully plan, secure necessary government approvals, finance, build, and operate the necessary infrastructure and LNG park. See "Risk Factors" in the company's 2014 Annual Report on Form 10-K, Quarterly Reports on Form 10-Q and other public filings and press releases. Anadarko undertakes no obligation to publicly update or revise any forward-looking statements.

Please also see our website at www.anadarko.com under "Investor Relations" for reconciliations of the differences between any non-GAAP measure used in this presentation, the appendix slides or the most directly comparable GAAP financial measures. Also on our website at www.anadarko.com is a glossary of terms.

Cautionary Note to Investors - The U.S. Securities and Exchange Commission (SEC) permits oil and gas companies, in their filings with the SEC, to disclose only proved, probable and possible reserves that meet the SEC's definitions for such terms. We may use terms in this presentation, such as "resources," "net resources," "net discovered resources," "gross resource," "estimated recoverable resources," "discovered resource opportunity," "relative net resources," "net resource potential," and similar terms that the SEC's guidelines strictly prohibit us from including in filings with the SEC. U.S. Investors are urged to consider closely the oil and gas disclosures in our Form 10-K for the year ended December 31, 2014, File No. 001-08968, available from us at www.anadarko.com or by writing us at: Anadarko Petroleum Corporation, 1201 Lake Robbins Drive, The Woodlands, Texas 77380 Attn: Investor Relations. You can also obtain this form from the SEC by calling 1-800-SEC-0330.

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Preserving Value & Positioning for the Future

Al Walker

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Differentiating Performance

- Proven Successful Track Record
- Deep and Balanced Portfolio
- Best-in-Class Capital Allocation
- Distinct Competitive Advantages
- Active Portfolio Management

Differentiating 5-Year Track Record

8+% Divestiture-Adjusted Sales-Volume Growth

$4.5+ Billion Adjusted Free Cash Flow

160+% Reserve Replacement

~$15/BOE F&D

~65% Deepwater Exploration/Appraisal Success

~4 BBOE Net Discovered Resources

~$12.5 Billion Asset Monetizations

Note: See appendix slides for definitions/reconciliations of non-GAAP financial measures

Differentiating Depth & Quality

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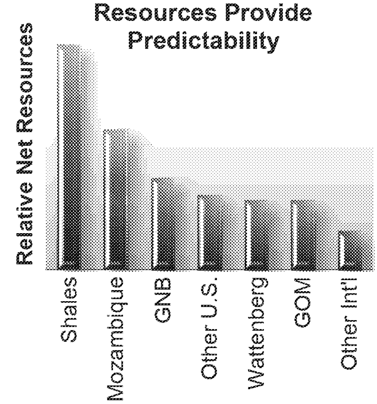
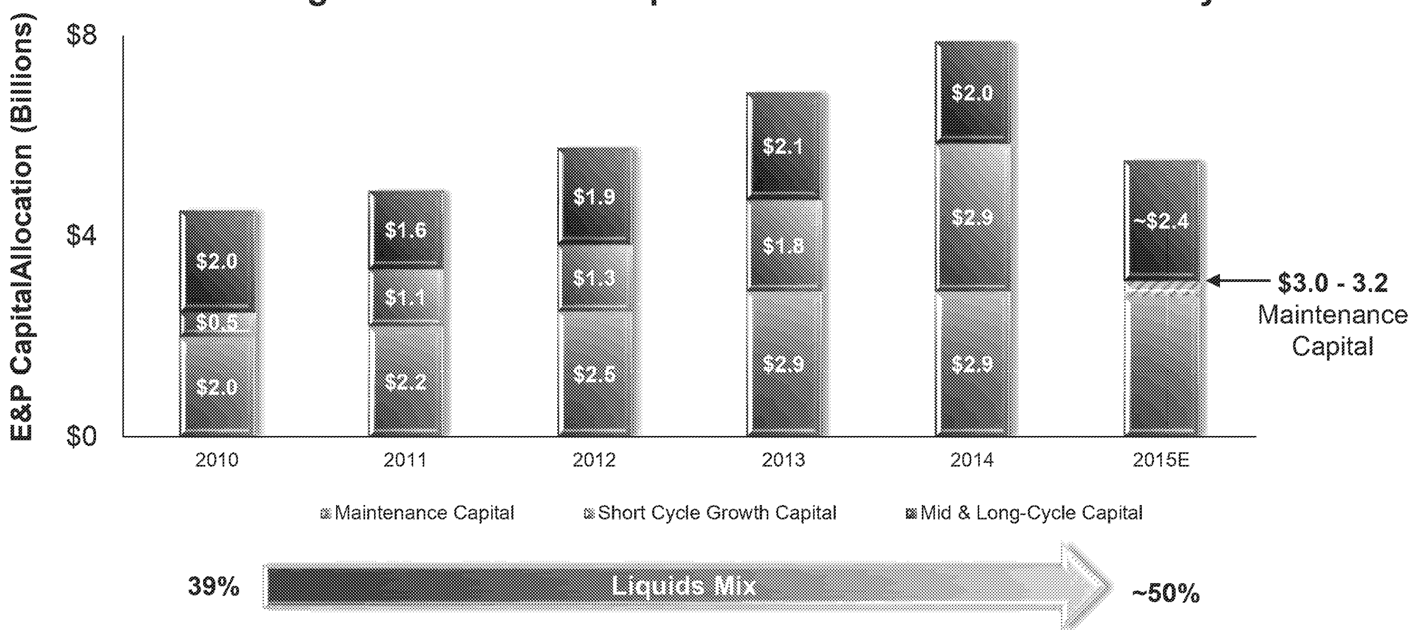
- Top-Tier U.S. Onshore Activation Costs: ~$35,000 per Flowing Barrel
- Visible Pipeline of High-Impact Mega Projects
- Exploration Optionality

8+ BBOE Lower-Risk Resources Provide Predictability



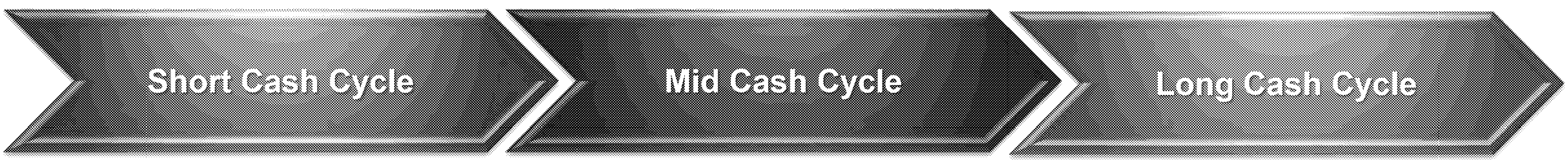
Advantaged Maintenance Capital* Provides Portfolio Flexibility



* Maintenance capital is defined as capital investments necessary to keep current-year sales volumes flat to previous year

Differentiating Capital-Allocation Approach

- Align Capital Investments with Anticipated Cash Inflows
- Maintain Flexibility with Short-Cycle U.S. Onshore Opportunities
- Leverage Midstream Advantage
- Advance Mid-Cycle Mega Projects
- Continue to Invest in Long-Cycle Exploration



<1 Year | 1 - 3 Years | 3+ Years

Differentiating Advantages

World-Class Exploration	Provides Portfolio Option Value
Industry-Leading Project Management	Enhances Project Value
Integrated Midstream Approach	Maximizes Upstream Value
Extensive Minerals-Interest Ownership	Drives Value & Efficiencies
Active Portfolio Management	Accelerates Cash Cycle & Value

Differentiating Portfolio Management

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- **Ongoing Commitment to Accelerate Value and Reduce Portfolio Complexity**
- **~$12.5 Billion in Monetizations 2010 - 2014**
  - ~$6 Billion Divestitures
  - $5+ Billion Carried-Interest Agreements
  - $1+ Billion Exploration Farm-Downs
- **$3+ Billion Inflows from WES and WGP to Date**
- **$700+ Million Divestiture Already in 2015**

*Does not include WES/WGP transactions

Preserving Value & Positioning for the Future

- Maintain Portfolio Flexibility to Accelerate as Returns Improve
- Focus on Driving Efficiencies and Cost Savings
- Exercise Financial Discipline
- Continue to be an Active Portfolio Manager

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2015 Initial Expectations

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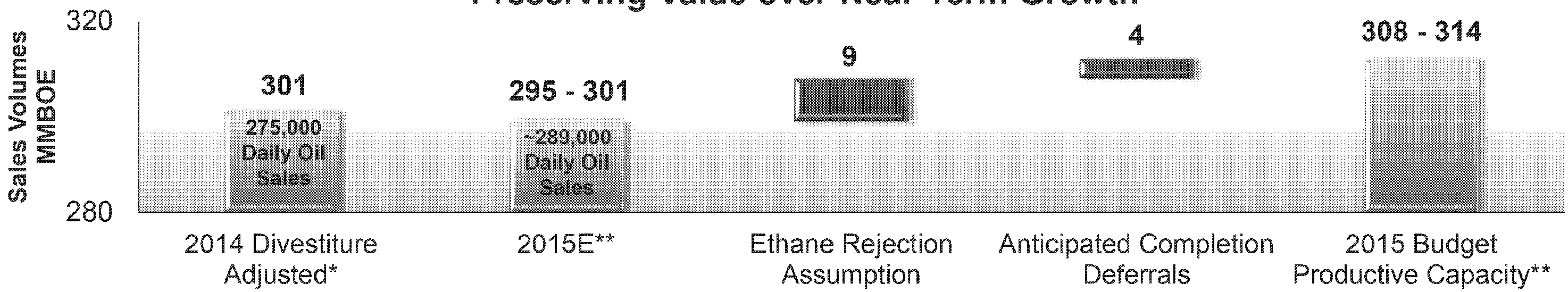
	2015 Expectations
Sales Volumes (MMBOE)**	295 - 301
Capital (Billions)[1]	$5.4 - $5.8
Reserve Replacement[2]	100+%
F&D ($/BOE)[2]	~$20

[1]Does not include WES capital investments
[2]Does not include potential Mozambique reserve adds

- ~5% YOY Oil Sales-Volume Growth
- Minimal Incremental Cost Savings Assumed
- 40% U.S. Onshore Rig Count Reduction
- ~125 Deferred U.S. Onshore Well Completions

Preserving Value over Near-Term Growth



* See 2014 divestiture-adjusted table attached to 3/3/2015 capital and guidance release
** Net of anticipated weather and facility downtime

Flexible Capital Allocation Preserves Value

2015 Capital Expectations: $5.4 - $5.8 Billion*

Corporate ~3%

Short Cash Cycle ~55%	Mid Cash Cycle ~30%	Long Cash Cycle ~12%
<1 Year	**1 - 3 Years**	**3+ Years**

Short Cash Cycle ~55% — <1 Year

- Wattenberg Generates 30+% BTAX ROR at Strip Prices
- Eagleford Generates 20+% BTAX ROR at Strip Prices
- Leverage Midstream Advantage

Mid Cash Cycle ~30% — 1 - 3 Years

- Build Foundation for Wolfcamp Growth
- Add Incremental Oil at K2 and Caesar/Tonga
- Advance Heidelberg and TEN Mega Projects for 2016 Start

Long Cash Cycle ~12% — 3+ Years

- Progress Mozambique LNG
- Advance Shenandoah to Development
- Advance Paon Commerciality
- Test Play-Opening Prospects in Colombia, Kenya and GOM

** Does not include WES capital investments*

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Preserving Financial Strength

Bob Gwin

Strong Financial Position

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- **~$3 Billion Cash-on-Hand***
- **Material Borrowing Capacity**
  - $3 Billion 5-Year Revolving Credit Facility
  - $2 Billion 364-Day Facility
  - $3 Billion Commercial Paper
- **Continue to be an Active Portfolio Manager**
  - $700+ Million Divestiture Announced
- **Anticipate Periodic WES and WGP Transactions**

Net Debt-to-Cap	YE 2014	Pro Forma YE 2014*
Anadarko Consolidated	26%	35%
Anadarko ex WES/WGP	21%	33%

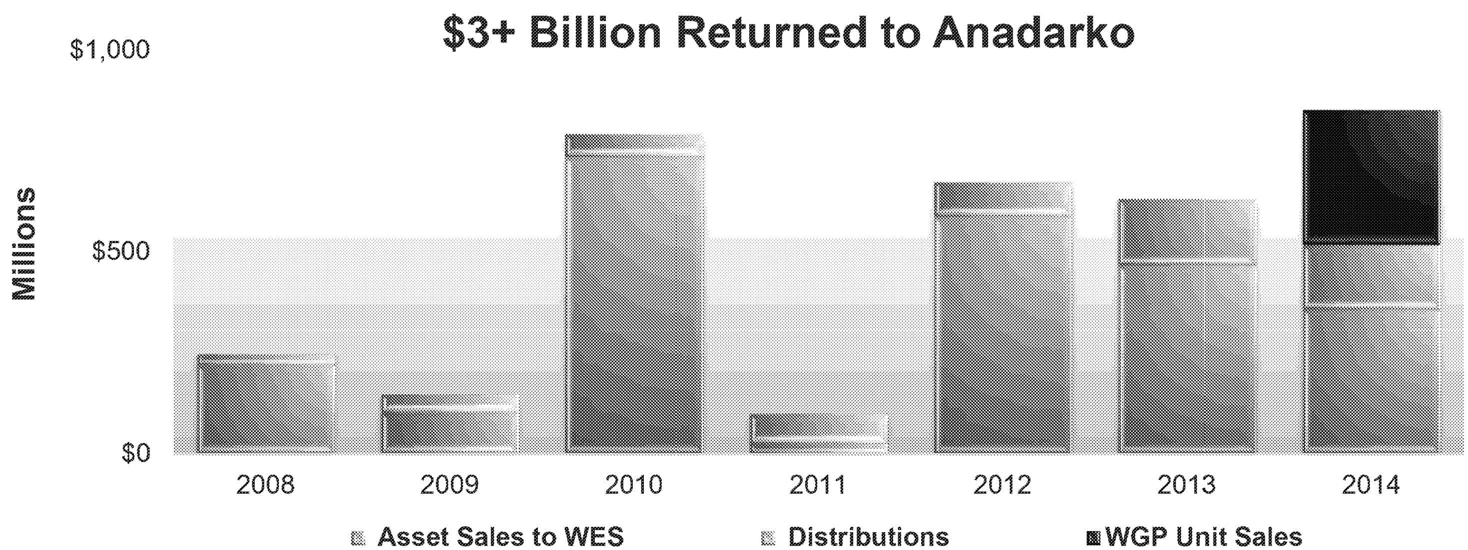
S&P	Moody's	Fitch
BBB	Baa2	BBB-
Stable	Stable	Positive

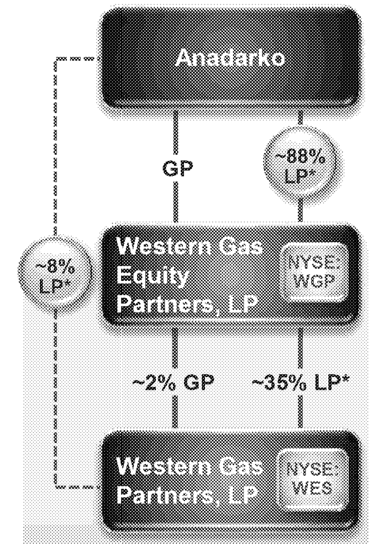
Strong Investment-Grade Ratings

* Post Tronox settlement and announced 2015 divestiture

WES & WGP: $15+ Billion Value for Anadarko

- Anticipate Periodic Transactions
- WES Independently Funds Significant Midstream Expansions
- Provides Visible Cash Source





~$12 Billion WGP Unit Value Owned by Anadarko**

* Fully Diluted
** As of 2/27/2015

2015 Multiples With/Without Hedging Impact

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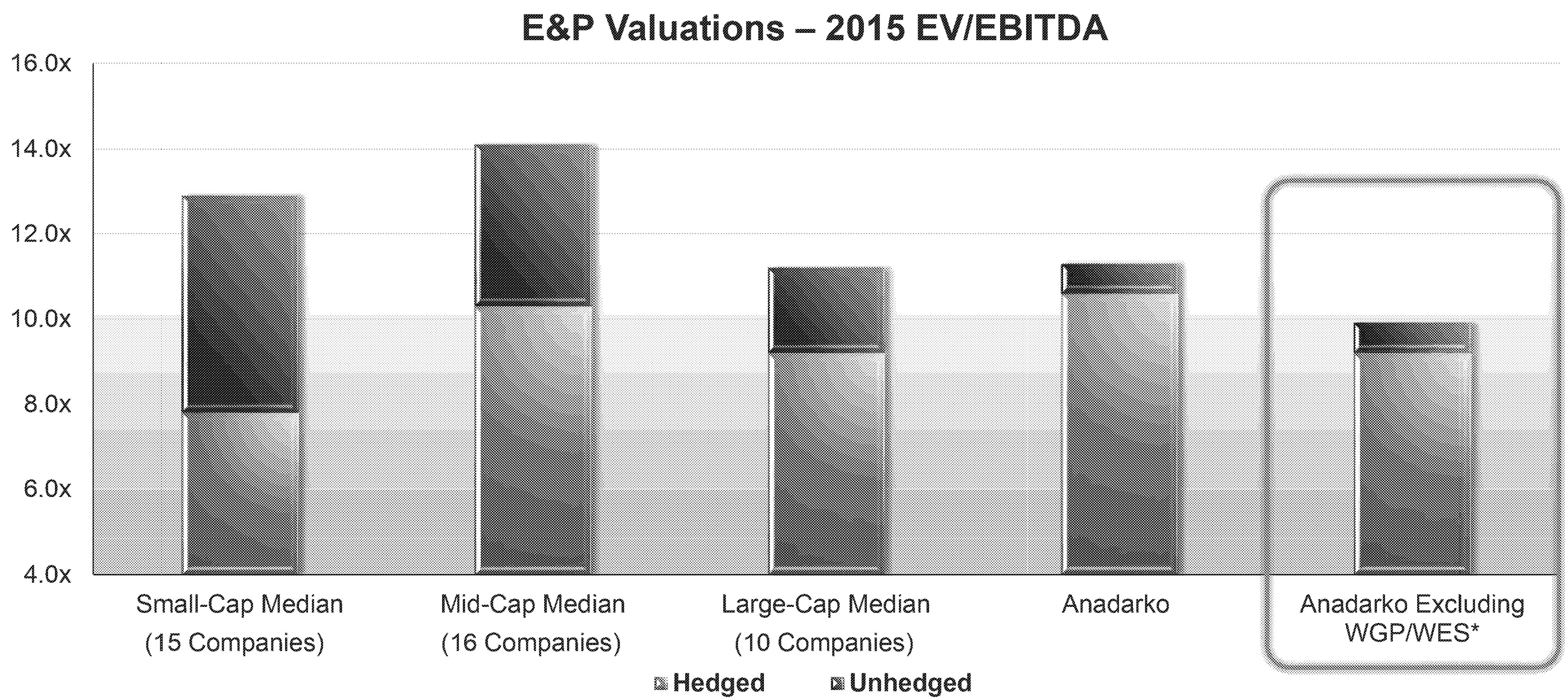

Source: Heikkinen Energy Advisors estimates (2/27/2015 Valuation Sheet)

** Does not include 2/27/2015 WGP enterprise value owned by Anadarko and forecasted 2015 WES EBITDA*

Financial Discipline as a Competitive Advantage

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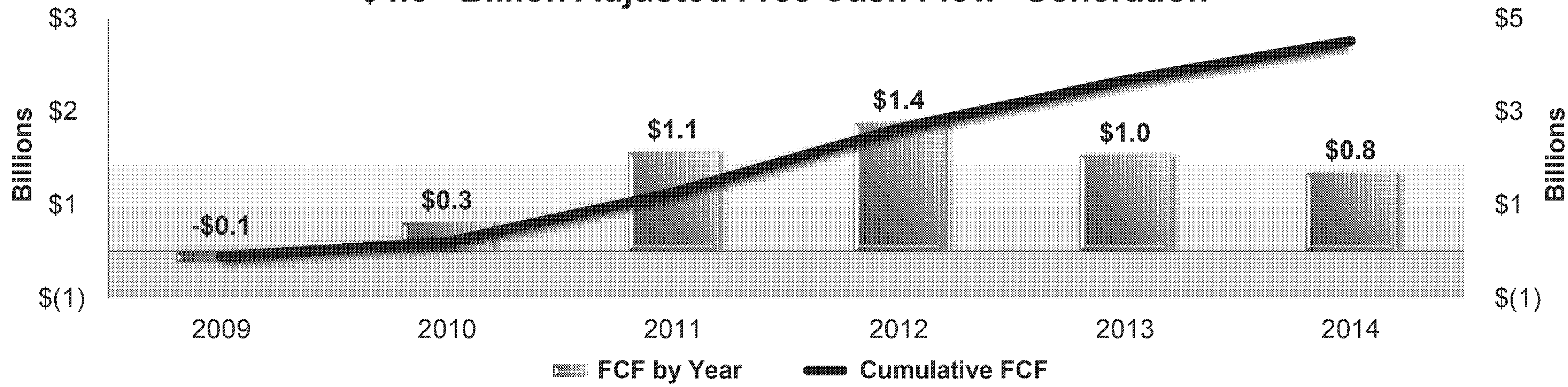
- Preserve Balance Sheet Strength
- Committed to Solid Investment Grade Rating
- Ongoing Portfolio-Management Activity

$4.5+ Billion Adjusted Free Cash Flow* Generation



Note: See appendix slides for definitions/reconciliations of non-GAAP financial measures
** Does not include WES capital investments*

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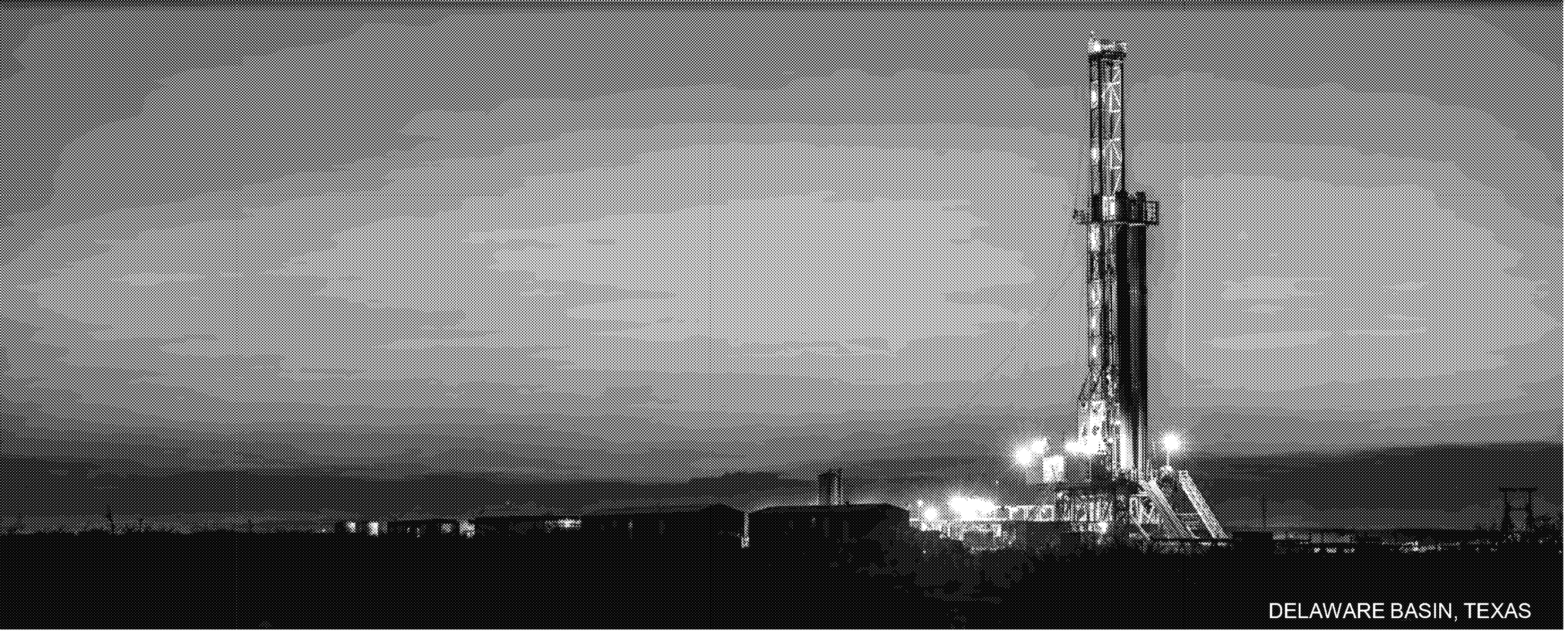

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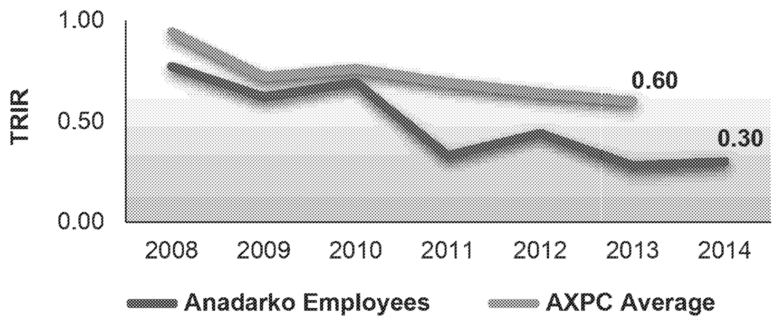
U.S. Onshore

Chuck Meloy

U.S. Onshore: 2015 Playbook

- Maintain High HSE Standards
- Leverage Continuous Improvement Culture
- Capture Supply Chain Savings
- Focus on Base Production
- Leverage Integrated Business Approach to Maximize Value
- Increase Activity when Costs Align with Commodity Prices
- Build Foundation for Wolfcamp Growth

Outstanding Safety Performance



Exploration
- Eagleford
- DJ Basin
- Delaware Basin
- Marcellus
- Haynesville

Drilling
- Utilize Flexibility from Staggered Rig Contracts
- 20% 2-Year Drilling Efficiency Improvement

Completions
- Increase EURs
- Water On-Demand
- Capture Savings with Well-to-Well Contracts
- Option to Accelerate when Costs Align with Commodity Prices

Production
- Low-Cost Operator
- Advanced Surveillance Technologies
- Integrated with Midstream
- Large Assets for Economies of Scale

Midstream & Takeaway
- WES/WGP
- Enable Upstream Growth
- Enhance Margins
- Enhance Liquid Recoveries
- Multiple Marketing Outlets

U.S. Onshore: Maintain Flexibility & Preserve Value

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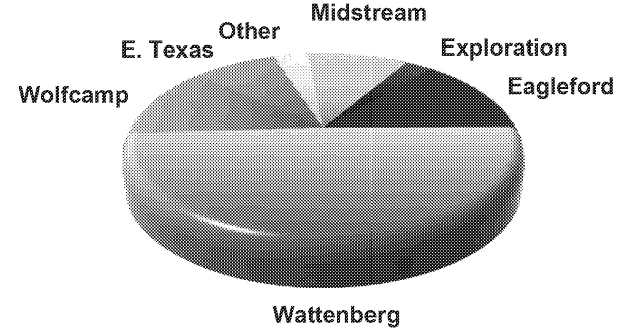
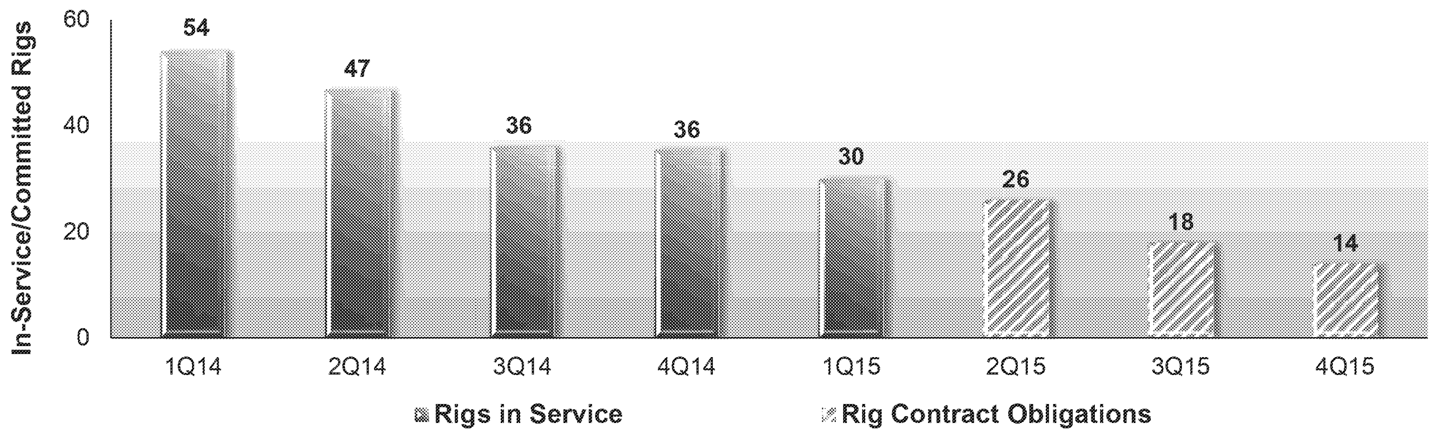
- Will Reduce Onshore Rig Count by 40% from 2014
- Defer ~125 Completions Until Costs Align with Commodity Prices
- 50% Capital Allocation to Wattenberg: 30+% BTAX ROR
- ~15% Capital Allocation to Eagleford: 20+% BTAX ROR
- Wolfcamp: Delineation and Enabling Infrastructure

2015 CAPITAL BUDGET
~$3.8 BILLION



Staggered Operated Rig Contracts Provide Flexibility



Wattenberg: World-Class Asset

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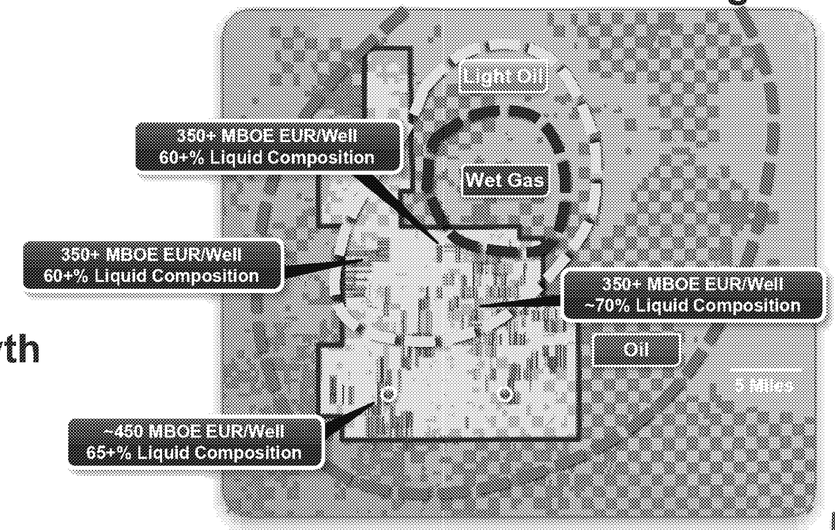
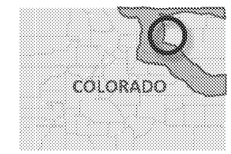
- **1.5+ BBOE Current Net Resources**
  - 500+ MMBOE Upside with Downspacing
- **~4,000 Identified HZ Drilling Locations**
- **Resilient Returns**
  - 30+% BTAX Returns in Current Environment
  - Minerals-Interest Uplift
- **Infrastructure in Place for Expanded Growth**

Consolidated Core Acreage

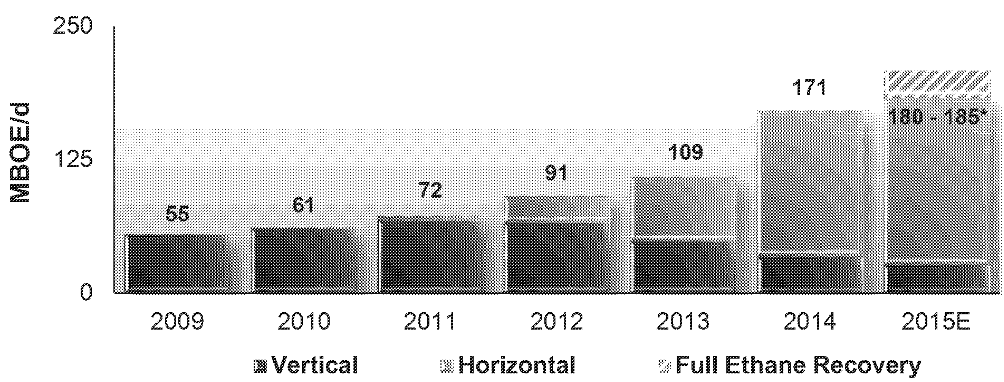


WATTENBERG
Net Acres: ~350,000



- APC Acreage
- APC Mineral Interest
- HZ Wells
- 24 Wells Per Section Downspacing Tests

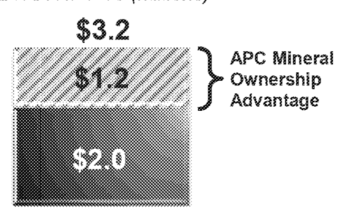
Wattenberg Net Sales Volumes



* Assuming partial ethane recovery

Anadarko Economics Enhanced by Minerals-Interest Ownership

BTAX NPV-10 (Millions)



Based on $3.6 million well cost and NYMEX strip as of 2/24/2015

2015 Planned Activity

- Operate ~9 Rigs
- Drill 280+ Wells (330+ Type-Well Equivalents)
- Defer ~70 Well Completions

Wattenberg Infrastructure: Staying Ahead of the Game

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Multiple Delivery Options to Maximize Value

Recent Additions

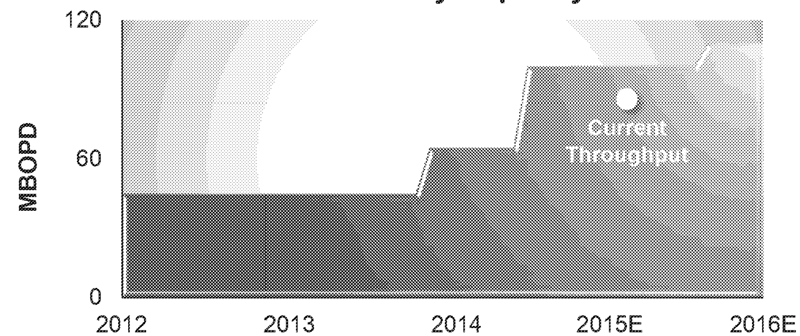
- 300 MMcf/d Lancaster Cryogenic Plant
- 150,000 Bbl/d Front Range NGL Pipeline
- ~80,000 Bbl/d White Cliffs Oil Pipeline

Expansions Under Way

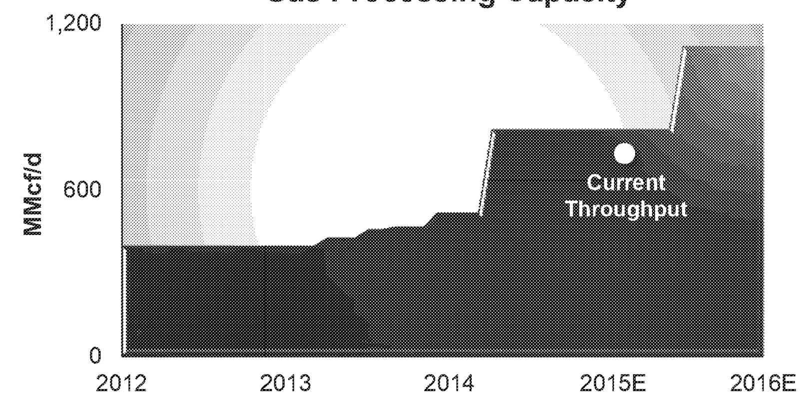
- Field Gathering and Compression
- 300 MMcf/d Lancaster II Cryogenic Plant

Year-End 2014 Infrastructure	
Gas Gathering Pipelines	3,100+ Miles
Oil Gathering Pipelines	200+ Miles
Processing Capacity	875 MMcf/d
Compression	197,000 HP
Gas Gathering System Capacity	685 MMcf/d
Oil Gathering System Capacity	125 MBOPD

Oil Takeaway Capacity



Gas Processing Capacity



Delaware Basin Wolfcamp: It's BIG

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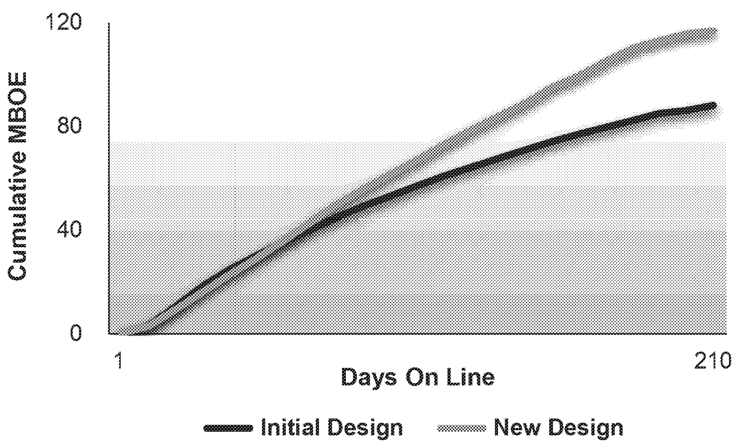
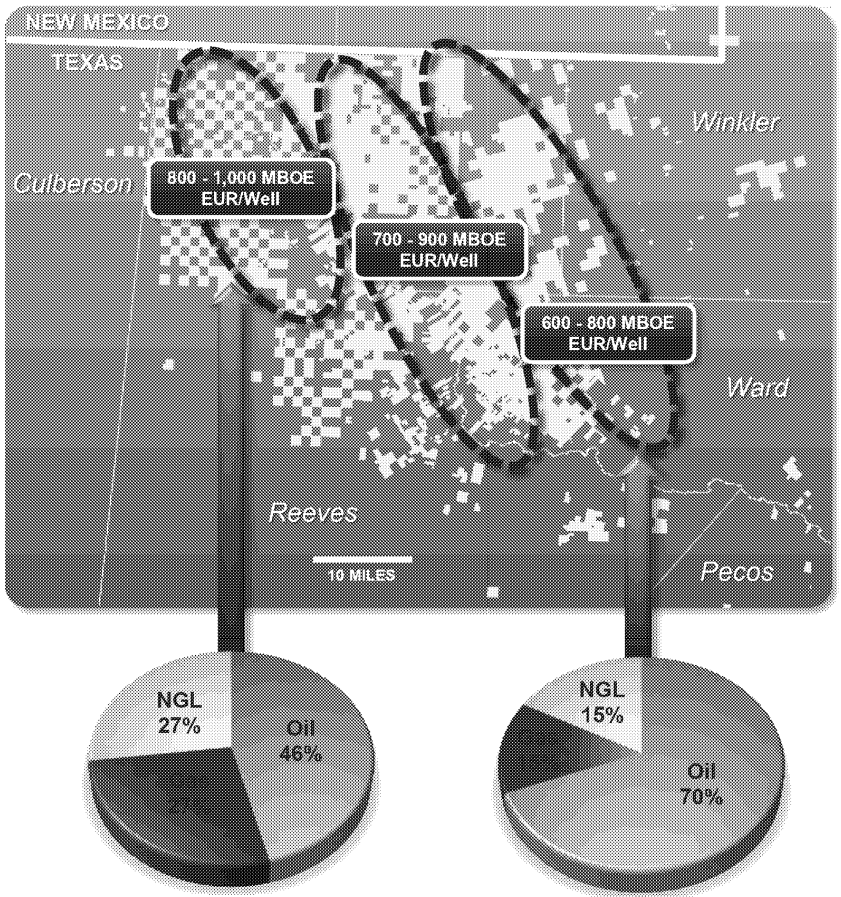
- **Activity Demonstrates Commerciality**
- **1+ BBOE Net Resource Potential**
  - 100+ MMBbl Original Oil in Place per Section
  - 5,000+ Identified Wolfcamp A Locations
- **Preparing for Full-Scale Development**

~30% Increase in EURs



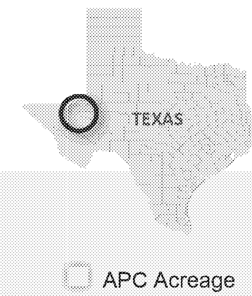
Top-Tier Acreage Position



DELAWARE BASIN

Gross Acres: ~610,000

Net Acres: ~255,000



TOP-TIER RESERVOIR CHARACTERISTICS

WOLFCAMP	
TVD (ft)	9,000 - 12,000
Gross Thickness (ft)	1,200 - 2,000
Porosity (%)	8 - 12

Delaware Basin: Building the Foundation for Future Growth

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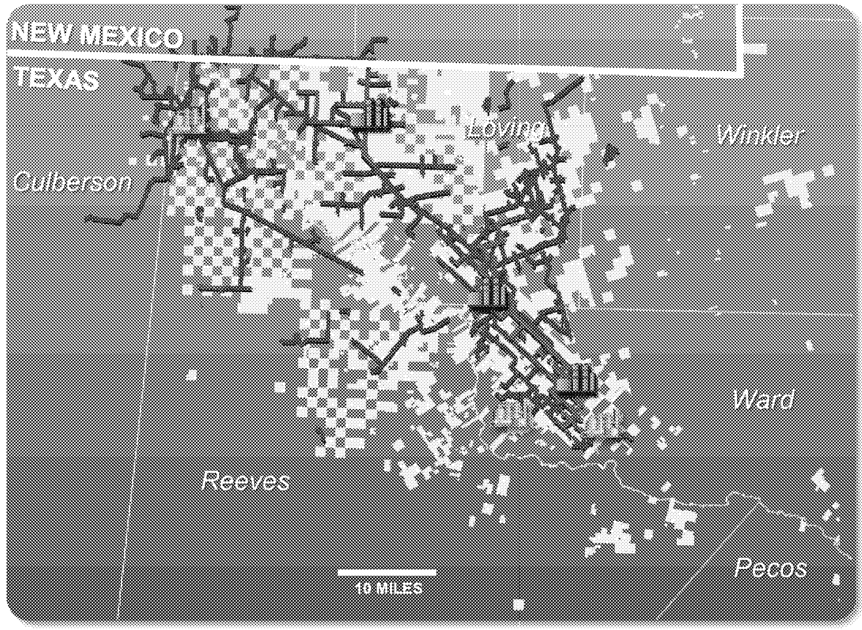
Year-End 2014 Infrastructure	
Gas Gathering Pipelines	780 Miles
Oil Gathering Pipelines	115 Miles
Compression	70,000+ HP
Gas Gathering Facilities	13
Water Gathering Pipelines	100+ Miles

Applying Proven Midstream Model

- Enables Operational Control
- Ensures Timely Well Connections
- Improves Price Realizations

APC, WES & JV Infrastructure



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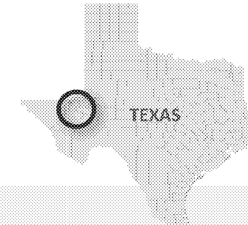

- APC Acreage
- Gas Gathering
- Oil Gathering
- Production Facility
- Processing Plant

2015 Planned Additions

- 190 Miles of Pipeline
- 30,000 BOPD Oil Processing
- 200 MMcf/d Cryo Gas Processing

Delaware Basin Wolfcamp: Advancing an Onshore Mega Project

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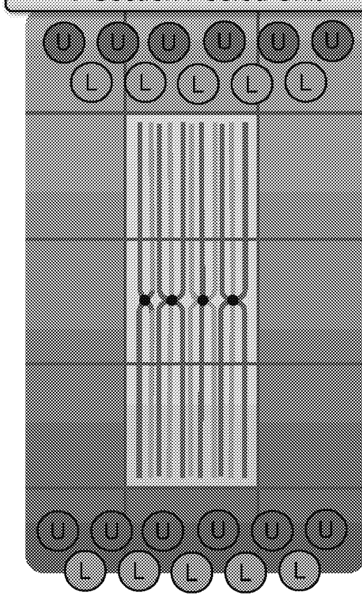
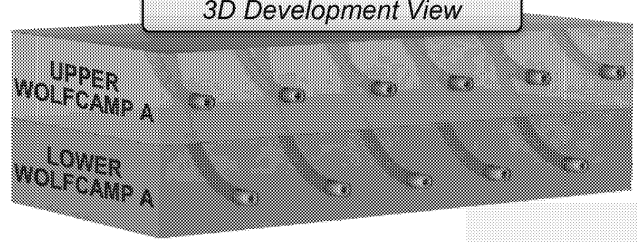
- **Complete Reservoir Evaluation and Lease-Commitment Activity**
  - Test Stacked-Pay Potential
- **Prepare Multi-Year Development Plan**
  - Optimize Spacing and Completion Design
  - Utilize Longer Laterals
  - Transition to Field-Wide Pad Activity
- **Expand Enabling Infrastructure**
  - Roads
  - Power
  - Water
  - Facilities
  - Gathering
  - Processing

Planned Development Options

3-Section Pooled Unit



3D Development View



- Opportunities to Pool Units
- 8 - 12 Wells/Section
- Sawtooth Development of Wolfcamp A Benches

U Upper Wolfcamp A
L Lower Wolfcamp A
• Surface Location

2015 Planned Activity
- Operate ~6 Rigs
- Drill 60 - 70 Wells
- Defer ~30 Well Completions

Eagleford: Maximizing Scale Advantages

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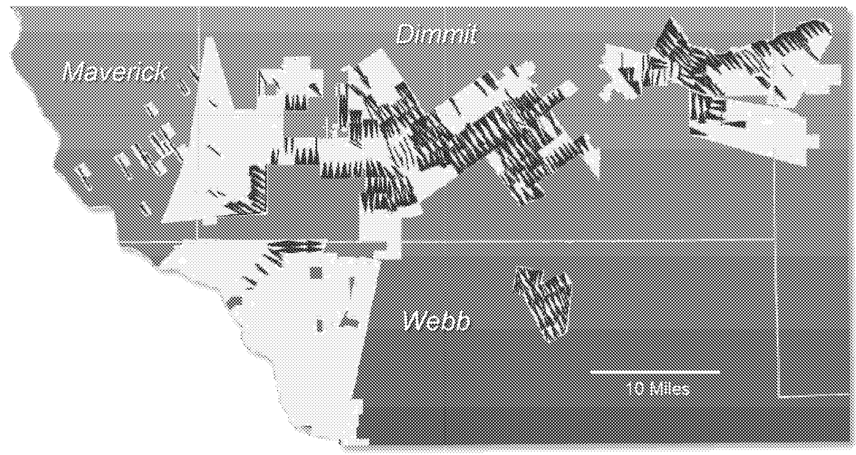
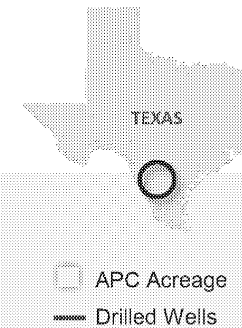
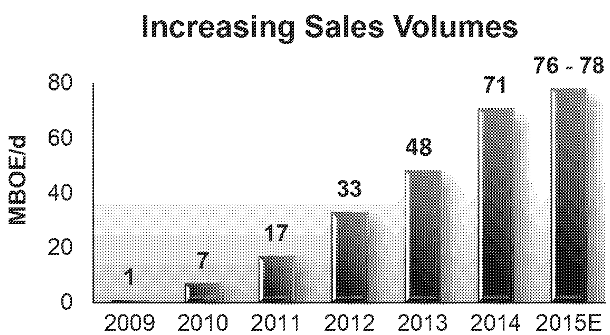
- **250+ MBOE/d Gross Processed Sales Volumes**
  - ~2,000 Identified Drilling Locations
  - Testing Stacked-Pay Potential
- **Reduced Rig Count from 10 to 5**
  - 20+% BTAX ROR at Strip Prices* and Current Costs
- **Best Drilling Cycle Times in Play**
  - Longer Laterals at Lower Cost
- **Infrastructure in Place**

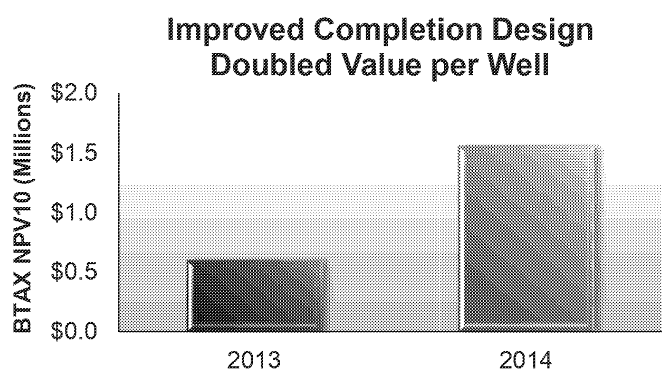
1,400+ Wells Drilled to Date



EAGLEFORD
Gross Acres: ~332,000
Net Acres: ~162,000







2015 Planned Activity
- Operate ~5 Rigs
- Drill ~200 Wells
- Defer ~30 Well Completions

* *As of 2/24/2015*

Eagleford: Large-Scale Infrastructure Advantages

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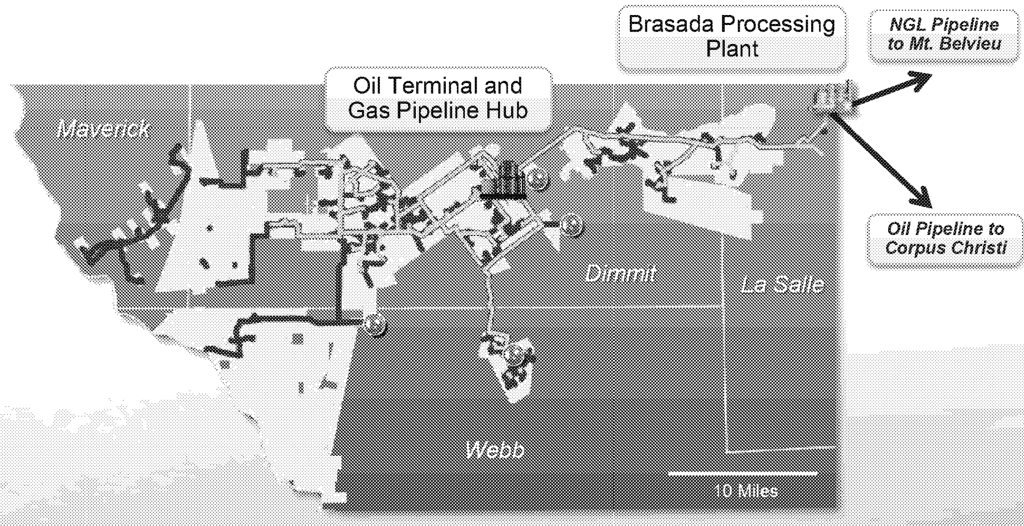
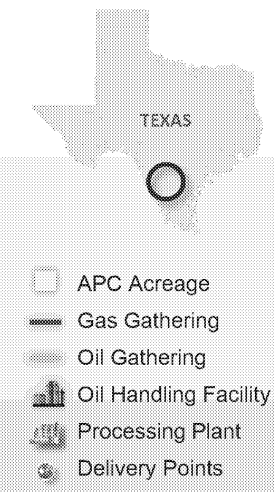
Year-End 2014 Infrastructure	
Oil Gathering Pipelines	241 Miles
Gas Gathering Pipelines	605 Miles
Compression	224,000 HP
Central Gathering Facilities	24
Central Production Facilities	138
Water Pipelines	312 Miles



EAGLEFORD
Gross Acres: ~332,000
Net Acres: ~162,000



- **Brasada Gas Plant**
  - Flexibility to Maximize Value
  - Direct NGL Access to Mt. Belvieu

U.S. Onshore: Delivering Capital-Efficient Liquids Growth

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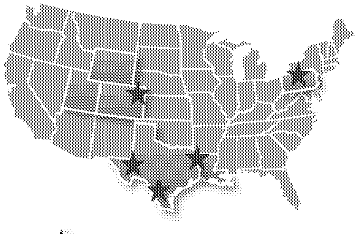
- Core Positions in 3 Major Horizontal Oil Plays
- Track Record of Top-Tier Results
  - ~92,000 BOE/d Growth in 2014
  - Wedge Volumes Added at ~$35,000 per Flowing Barrel
- Well Positioned for 2015



U.S. Onshore	Net Sales Volumes (MBOE/d)						
	2009	2010	2011	2012	2013	2014	2015E
Total Sales Volumes*	326	359	407	485	553	644	632 - 642
Liquids (MBbl/d)*	68	89	113	140	169	246	252 - 262
Wattenberg HZ	-	-	4	22	56	124	153 - 156
Eagleford	1	7	17	33	48	71	76 - 78
Wolfcamp	-	-	-	-	1	7	13 - 15
E. Tx/N. La HZ	-	6	9	23	41	48	46 - 48
Marcellus	1	6	23	54	85	95	80 - 85

~$13/BOE Development Costs

** Divestiture-adjusted*

NYSE: APC | www.anadarko.com

INVESTOR RELATIONS

John Colglazier
Senior Vice President
832/636-2306

Robin Fielder
Director
832/636-1462

Jeremy Smith
Director
832/636-1544

International & Deepwater Operations

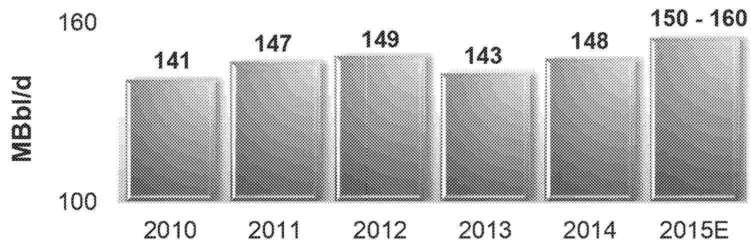
Jim Kleckner

High-Impact Projects Deliver Differentiating Value

NYSE: APC | www.anadarko.com

- High-Quality Assets
- Industry-Leading Project Management
- Manage Portfolio Risk and Accelerate Value

Stable Higher-Margin Liquids Sales Volumes



2015 Expectations

- ~$1.4 Billion Capital
- 180 - 185 MBOE/d Sales Volumes

Note: See appendix slides for definitions/reconciliations of non-GAAP financial measures

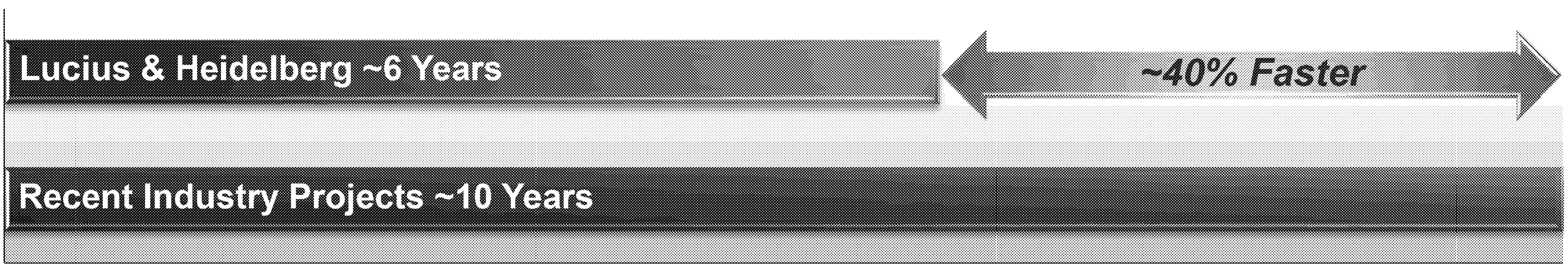
Industry-Leading Project Management Enhances Value

NYSE: APC | www.anadarko.com

- Excellent Safety Performance
- Project Delivery Track Record
- Efficient Reservoir Characterization
- Standardization and Contractor Continuity
- Knowledge Transfer
- Leader in Deepwater Drilling

Anadarko is Fast & Efficient (IPA)

Anadarko's Project Management is Adding ~$1 Billion Gross Value to Each Project



Years from Discovery to First Production

Advancing Mega Developments

NYSE: APC | www.anadarko.com

- **Lucius Ramping Toward Capacity**
- **Caesar/Tonga Adding Incremental Oil Volumes**
- **Heidelberg on Track for First Oil in 2016**
- **Ghana TEN on Track for First Oil in 2016**
- **Mozambique LNG Development Advancing to FID**

DESIGN ONE: BUILD TWO

Lucius: 80,000 BOPD Spar
Sanction to First Production: 3 Years

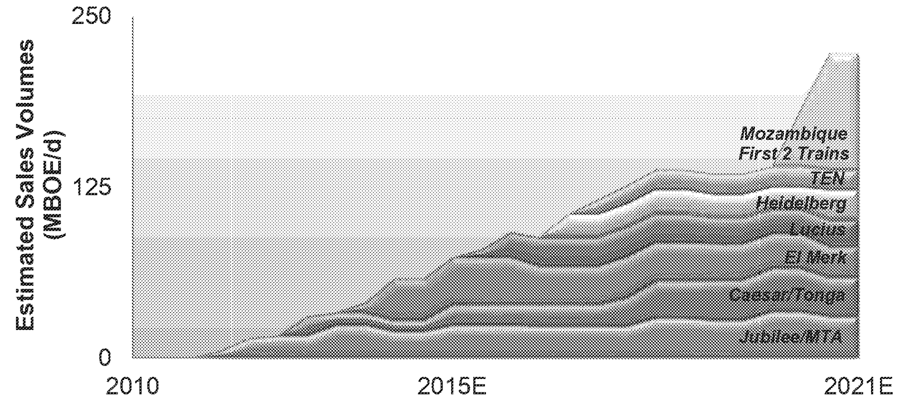
Heidelberg: 80,000 BOPD Spar
Sanction to First Production: 3 Years

Mega Projects Provide Significant Volumes & Cash

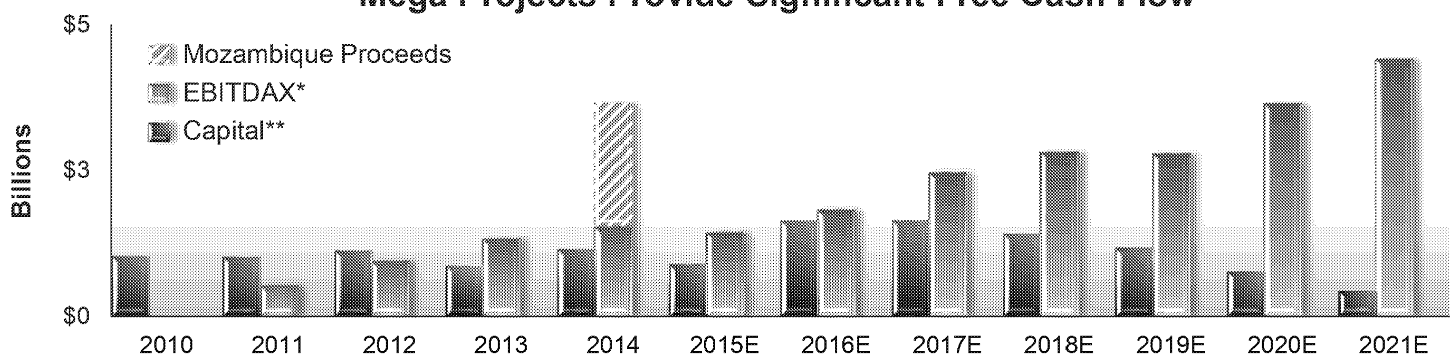
NYSE: APC | www.anadarko.com

- **Consistently Delivering High-Value Growth**
- **$3.5+ Billion Value Accelerated**
  - Lucius: $476 Million Carry for 6.2% Interest
  - Heidelberg: $860 Million Carry for 12.75% Interest
  - Mozambique: $2.1 Billion Net Divestiture for 10% Interest
- **Transitioning Next-Generation Projects**

Visible Growth



Mega Projects Provide Significant Free Cash Flow



* Based on strip pricing as of 02/24/2015

** ~60% Mozambique project financing assumed

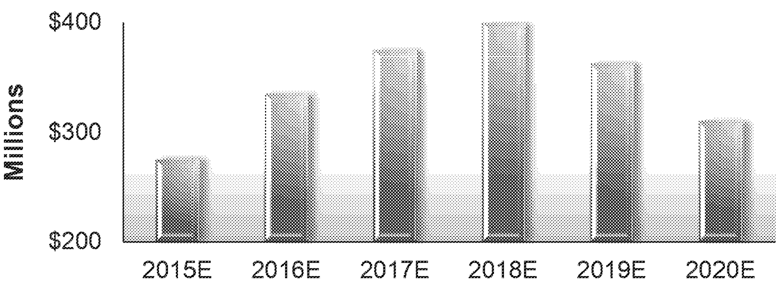
Note: See appendix slides for definitions/reconciliations of non-GAAP financial measures

Lucius: Differentiating Value

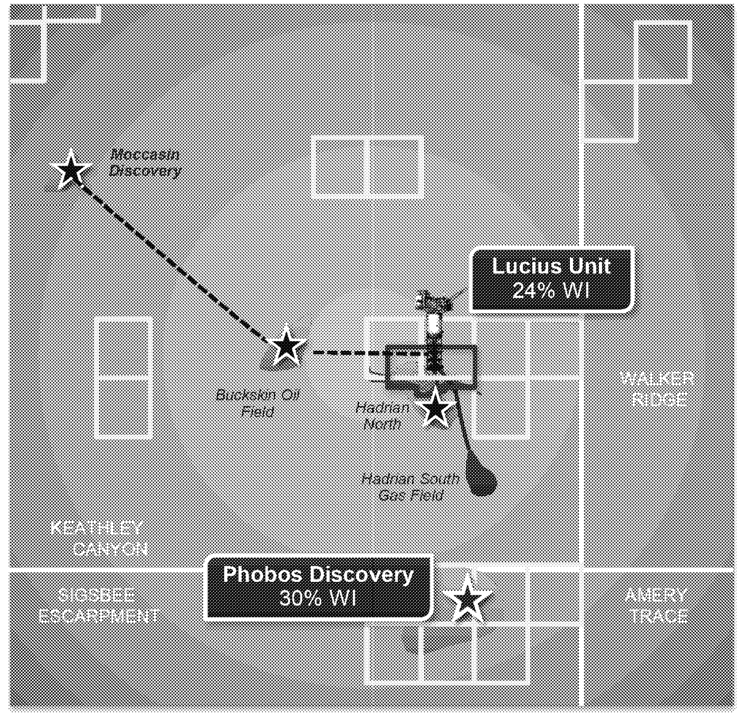
NYSE: APC | www.anadarko.com

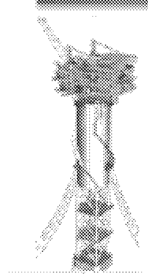
- **$2+ Billion BTAX Net Value**
  - Development Capital Carried
  - 1-Year Anticipated Payout
- **First Oil 3 Years from Sanction**
  - Ramping Toward Capacity
- **World-Class Reservoir Quality**
- **Enhancing Value Through Infrastructure**
  - Hadrian South PHA
  - Buckskin/Moccasin PHA
  - Pursuing Additional Opportunities

Forecasted Free Cash Flow*



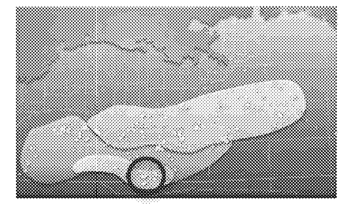
** Based on strip pricing as of 02/24/2015*





Lucius: Anadarko's Largest Spar	
Capacity	80,000 BOPD, 450 MMcf/d
Spar Diameter	110 Feet
Spar Length	605 Feet
Hull Weight	23,000 Tons
Water Depth	7,100 Feet

GULF OF MEXICO
Gross Acres: ~2.3 Million



- APC WI Block
- APC Discovery
- Industry Discovery
- Oil Field
- Gas Field
- Subsea Tie-Back

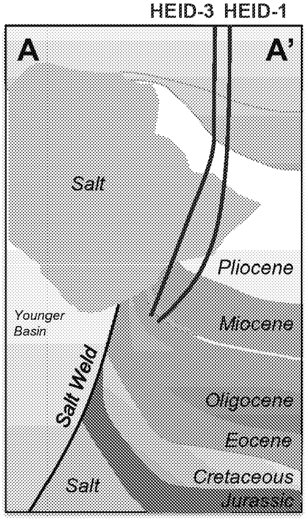
300+ MMBOE Gross Resources

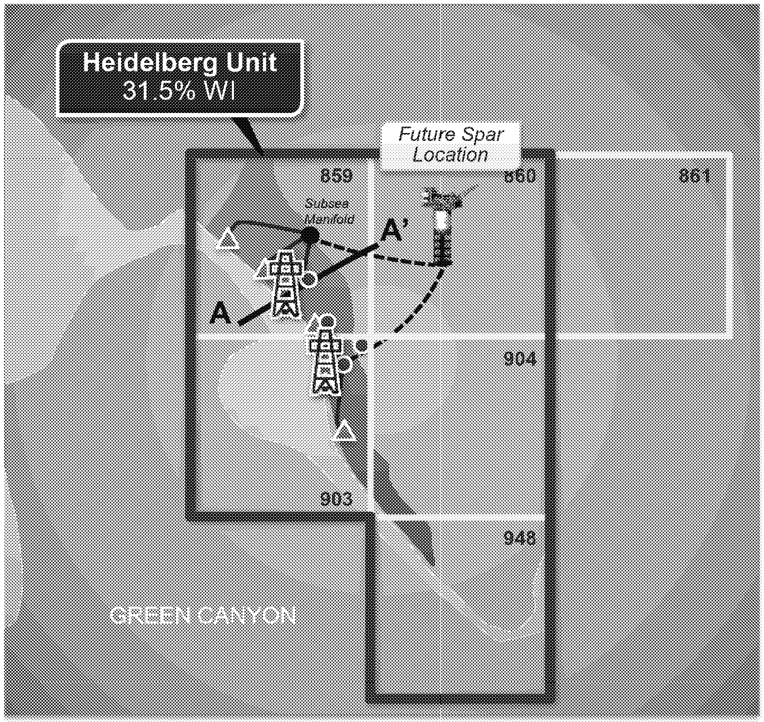
Note: See appendix slides for definitions/reconciliations of non-GAAP financial measures

Heidelberg: Replicating Lucius Success

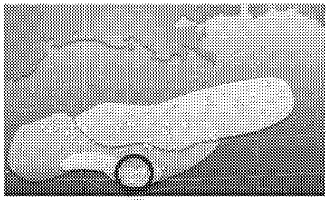
NYSE: APC | www.anadarko.com

- **First Oil Anticipated Mid-2016**
  - 3 Years from Sanction
  - Project ~75% Complete
  - 2 Rigs Drilling Development Wells
- **Utilizing Lucius Spar Design**
  - Accelerates First Oil by 18 Months
  - Reduces Execution Risk and Cost
- **200 - 400 MMBOE Gross Resources**





GULF OF MEXICO
Gross Acres: ~2.3 Million



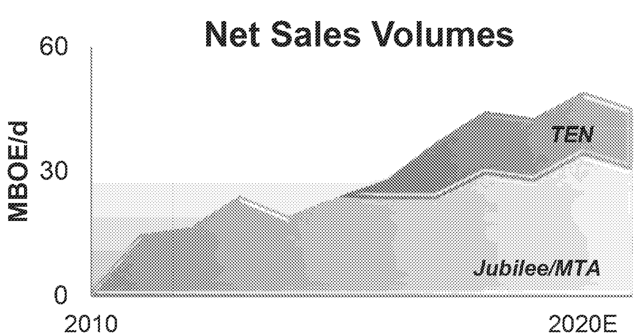
- APC WI Block
- Successful Well
- Planned Drilling
- Oil Field
- Salt
- Subsea Tieback

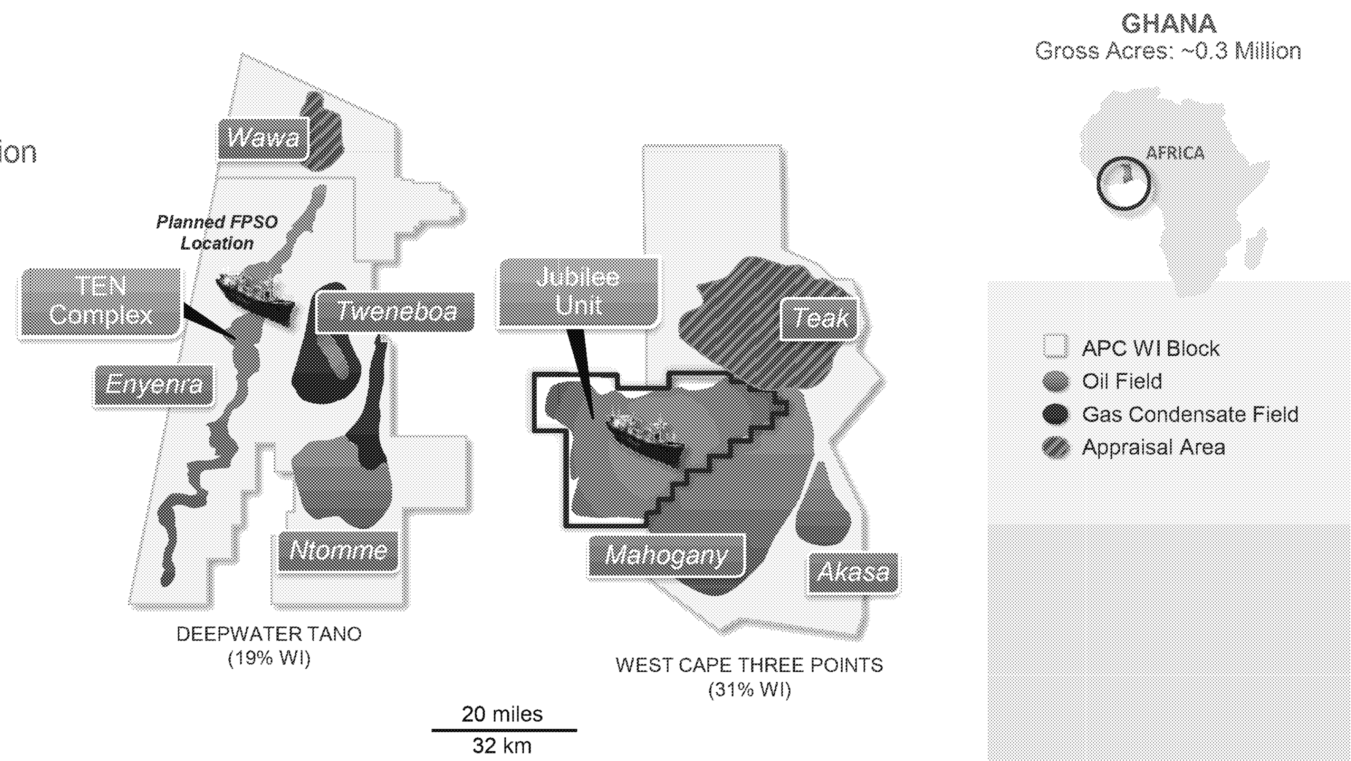
$860 Million Carried-Interest Agreement

Ghana: Premium-Value Oil Growth

NYSE: APC | www.anadarko.com

- **Jubilee: Producing 100,000+ BOPD**
  - High Margins: $90/Bbl EBITDAX in 2014
  - 125+ MMBO Produced Since 2010
  - Gas Off-Take to Enable Increased Oil Production
- **TEN: 80,000 BOPD FPSO**
  - First Oil Anticipated Mid-2016
  - Project ~50% Complete
  - On Budget and On Schedule
- **MTA: Potential Jubilee Tie-Back**





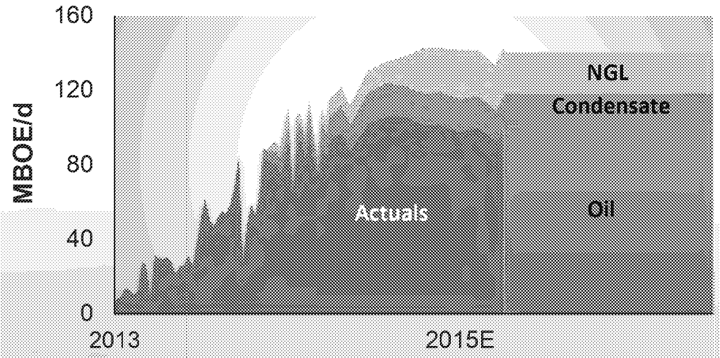
Note: See appendix slides for definitions/reconciliations of non-GAAP financial measures

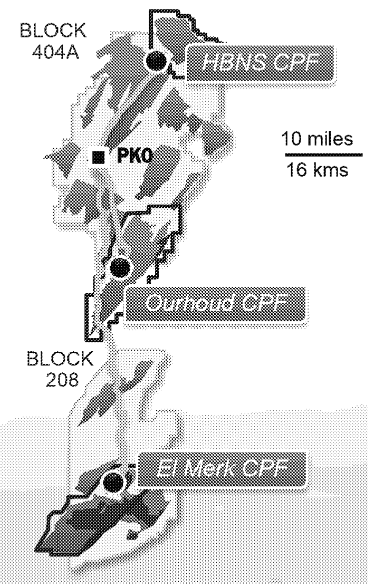
Algeria: 3 World-Class Developments in Sahara Desert

NYSE: APC | www.anadarko.com

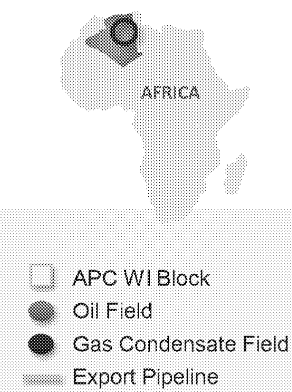
- **High Margins: $72/Bbl EBITDAX in 2014**
- **El Merk Drives Record Net Production in 2014**

El Merk
140+ MBbl/d Gross Sustained Rates





ALGERIA
Gross Acres: ~0.5 Million



Approaching 2 Billion Barrels Cumulative Oil Production

EL MERK CPF, ALGERIA

Mozambique LNG: Competitive Global LNG Supply Source

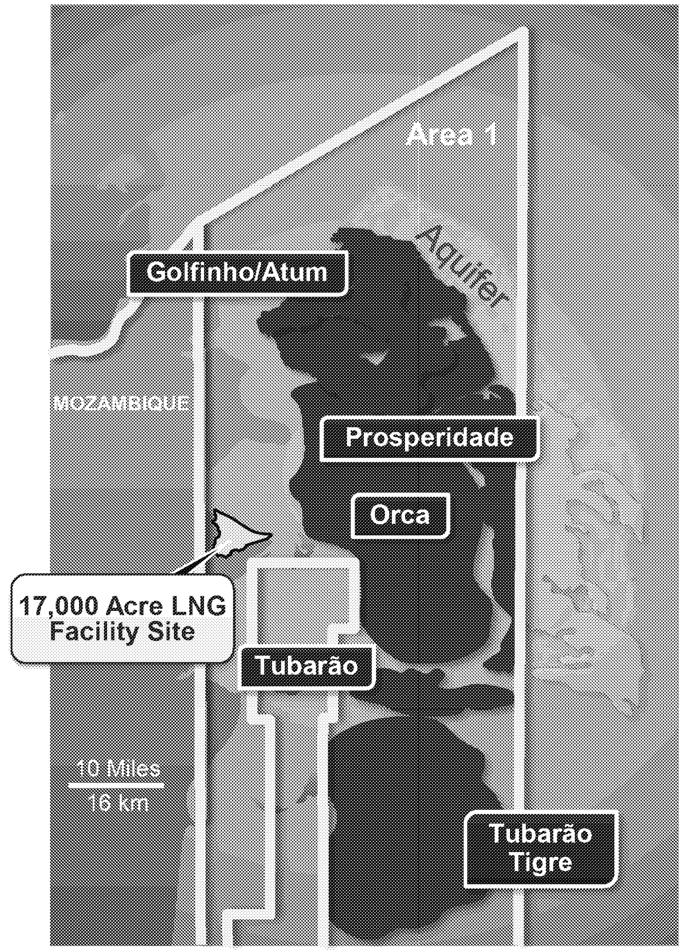
NYSE: APC | www.anadarko.com

Enormous Recoverable Resources
- 75+ Tcf on Offshore Area 1
- Scalable Onshore Development to 50+ MMTPA

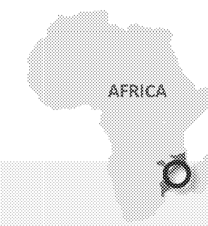
Attractive Cost Advantages
- Close Proximity to Shore
- Natural Harbor
- Direct Subsea to Shore Development
- High Well Deliverability
- Access to Premium Asian Markets

Advantaged Economics
- 20-Year Off-Take HOAs
- Pricing Mechanism Protects Economics

Financially Derisked
- $2.1 Billion Net Monetization Proceeds
- Material Project Financing Available



MOZAMBIQUE OFFSHORE AREA 1
Gross Acres: 1+ Million



APC WI Block
Natural Gas Field

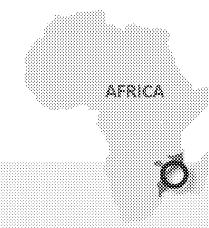
Mozambique LNG: Progressing World-Class Project to FID

NYSE: APC | www.anadarko.com

- Independent Certified Reserves → Sufficient to Support Initial Trains
- Establishing Legal & Contractual Stability → Decree Law Gazetted
- Evaluating Competitive FEEDs → Contractor Decision Pending
- Capturing Market → 8+ MMTPA Non-Binding HOAs
- Project Financing → 60+% Funding Indications Received

Pace to be Dictated by Government Agreements and Approvals

MOZAMBIQUE OFFSHORE AREA 1
Gross Acres: 1+ Million

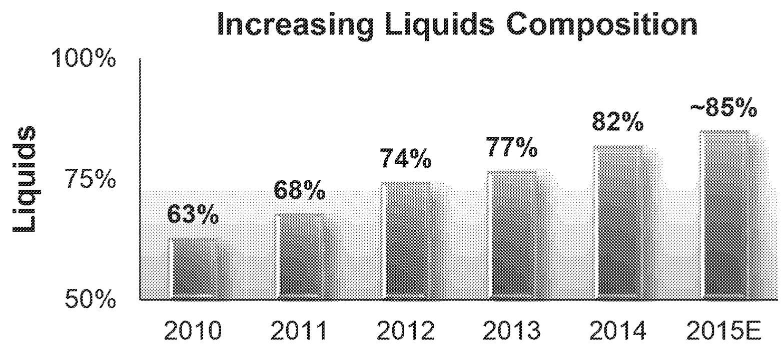


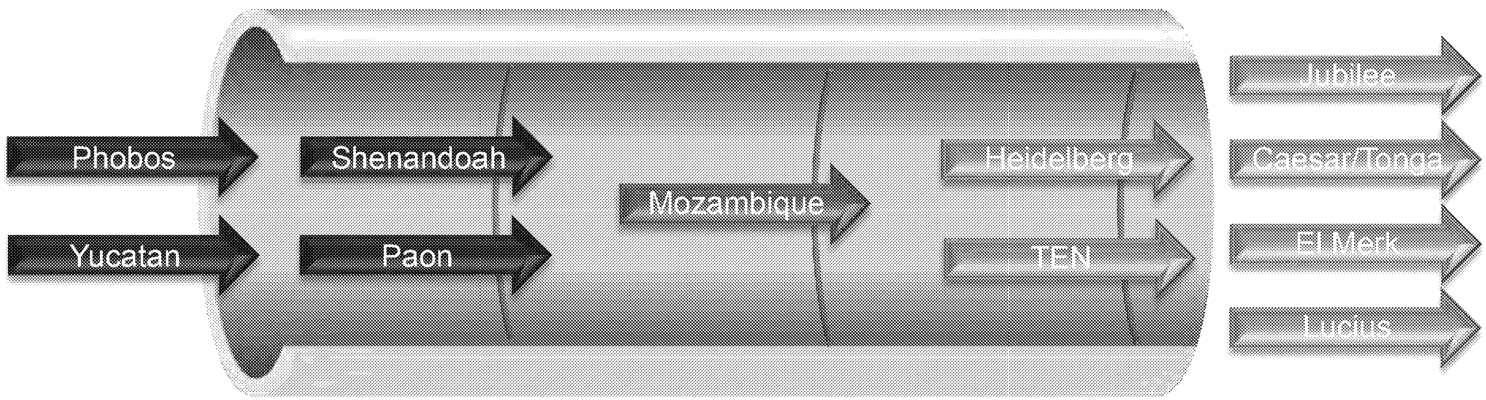
75+ Tcf Estimated Recoverable Resources

Continuous Mega-Project Pipeline Delivering Results

NYSE: APC | www.anadarko.com

- **Growing Long-Life, High-Margin Oil Production**
- **Advancing Multiple Development Projects**
- **Appraising Next-Generation Projects**
- **Managing Portfolio Risk and Accelerating Value**
  - ~$1.6 Billion China and Vito 2014 Divestitures





NYSE: APC | www.anadarko.com

International & Deepwater Exploration

Bob Daniels

INVESTOR RELATIONS

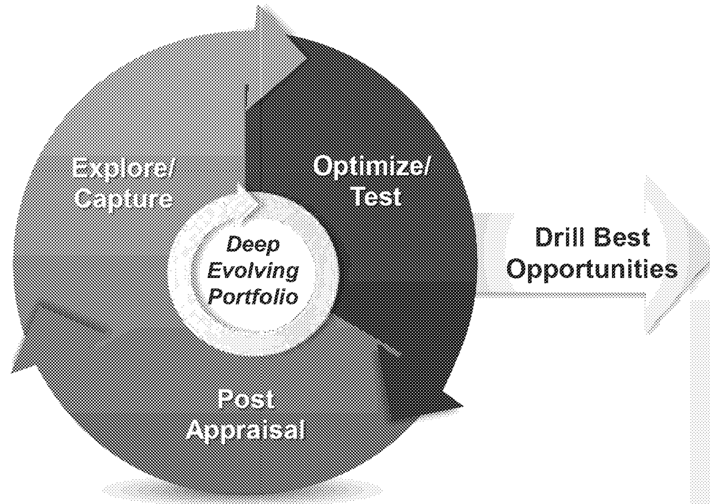
John Colglazier
Senior Vice President
832/636-2306

Robin Fielder
Director
832/636-1462

Jeremy Smith
Director
832/636-1544

Proven Exploration Strategy

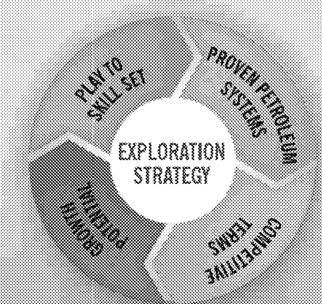
- **Consistent**
  - Focus on Strengths
  - Portfolio-Based Decisions
  - Risk Assessment
- **Focused on Value Creation**
  - Early, Low-Cost Entry
  - Optimize Working Interest
  - Commercial Leverage
- **Talented Oil Finders**
  - Culture of Creativity
  - Petroleum System Foundation
  - Appropriate Technology Application



5-Year Track Record

~65% Deepwater Success

~4 BBOE Net Discovered Resources



2007	2008	2009	2010	2012	2013	2014
Jubilee	Wahoo	Shenandoah Lucius Itaipu Vito Heidelberg	Prosperidade Enyenra	Golfinho/Atum	Orca	Tubarão Tigre

TOP-10 DEEPWATER DISCOVERIES*

* IHS Energy, January 2015

Creating Unmatched Value with Optionality

~$10 Billion Capital Invested
2005 - 2014

~6.5 BBOE	Net Discovered Resources
~$13 Billion	Monetized
~5 BBOE	Resources Retained
~250 MBOE/d	Net Production

DRIVING VALUE IN 2014

Discoveries
- Tubarão Tigre
- Tembo

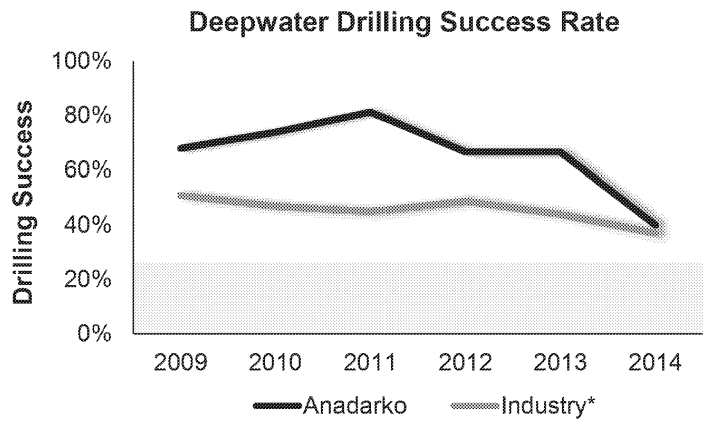
Appraising
- Shenandoah
- Paon
- Orca
- Tubarão Tigre

Developing
- Lucius: 1st Oil
- Heidelberg
- TEN
- Mozambique LNG

Monetized
- Mozambique WI
- Vito

Exploration Successes in 2014

- **Leveraged Our Success**
  - ~$200 Million Funding Through Farm-Outs
- **$3+ Billion Monetizations Closed**
  - Mozambique
  - Vito and Prospects
- **~200 MMBOE Net Discovered Resources**
- **Doubled Acreage Position in Colombia**



#3 *2014 Top-10 Deepwater Discovery**

TUBARÃO TIGRE-1

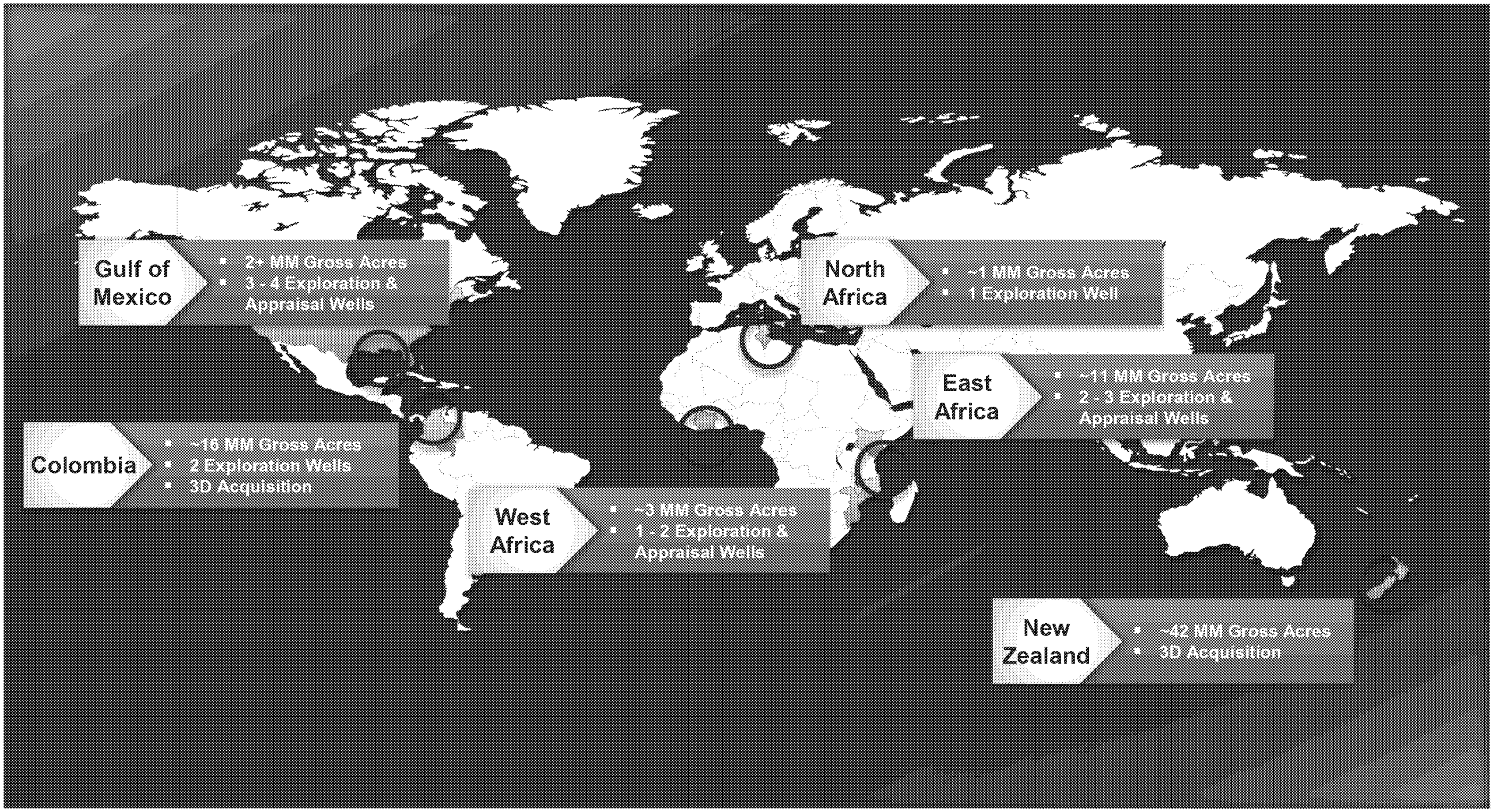
An Active Start to 2015

- **Gulf of Mexico: Drilling Yeti Prospect**
- **Colombia: Spud Play-Opening Opportunity**
- **Mozambique: Successfully Completed Deepwater Exploration Program**
  - 75+ Tcf Discovered to Date

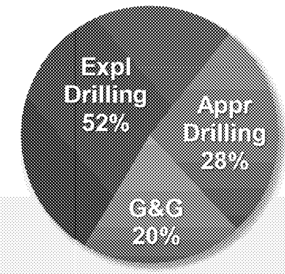
** IHS Energy, January 2015*

2015 Deepwater & International Exploration Activity

NYSE: APC | www.anadarko.com



2015 CAPITAL BUDGET ~$600 MILLION



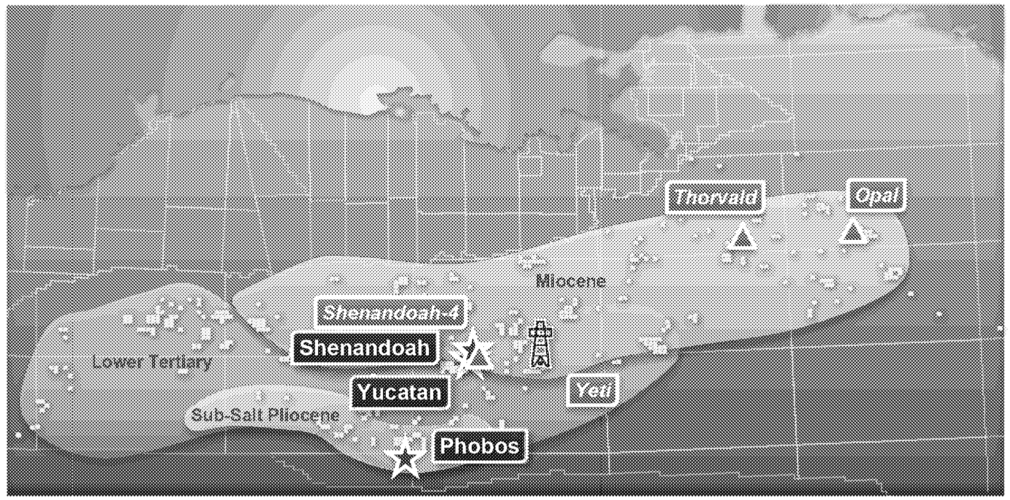
2015 Planned Activity

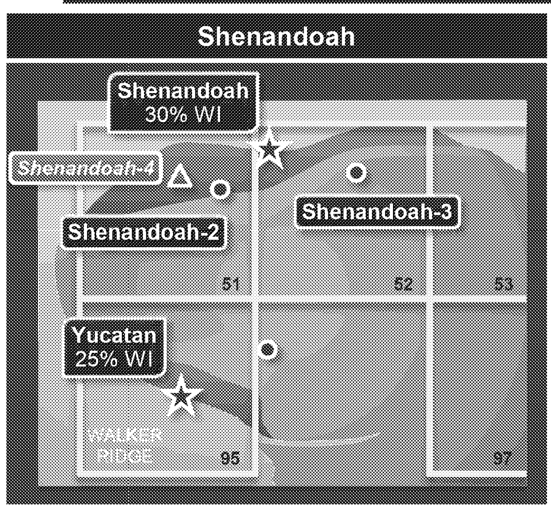
- Drill 9 - 12 Wells
- Target 700+ MMBOE Net Discovered Resources

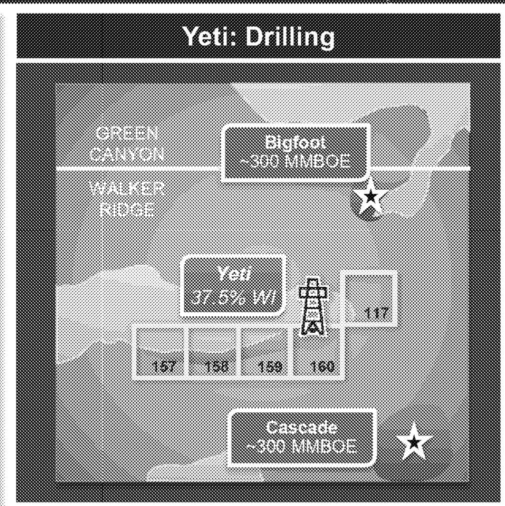
2015 Gulf of Mexico Exploration Activity

NYSE: APC | www.anadarko.com

- **Shenandoah: Advancing Toward Development**
  - Appraisal Well Up-Dip to Shenandoah-2
- **Yeti: Miocene Subsalt 3-Way Trap**
- **Opal: Miocene Unconfined Fan**
- **Thorvald: Subsalt 3-Way Trap**
- **Phobos: Potential Appraisal**







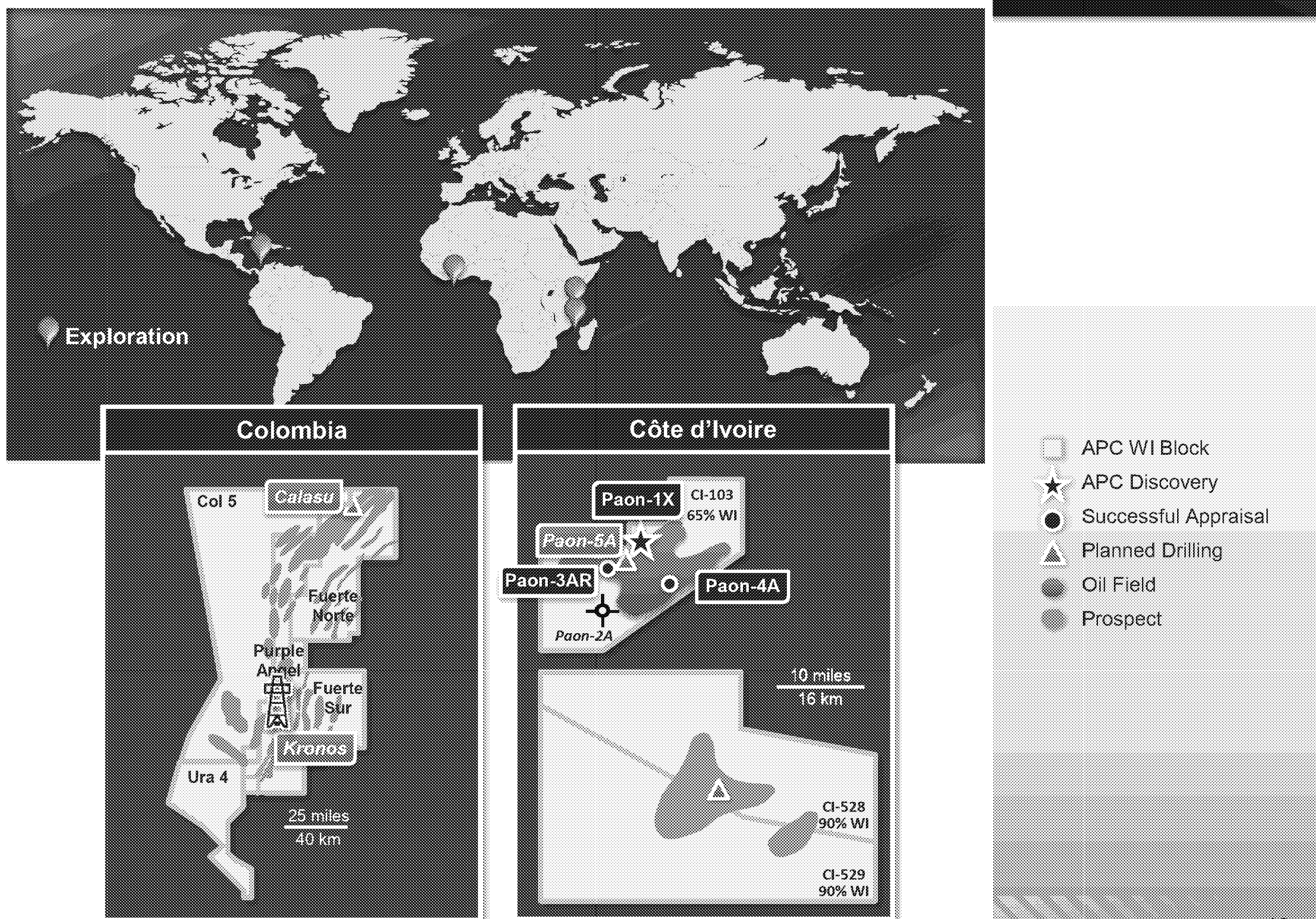
GULF OF MEXICO
Gross Acres: ~2.3 Million
3 - 5 Gross Wells

APC WI Block
APC Discovery
Successful Appraisal
Planned Drilling
Industry Discovery

2015 International Deepwater Exploration Activity

NYSE: APC | www.anadarko.com

- **Côte d'Ivoire**
  - Advancing Toward Commerciality
  - Paon: Appraisal Well and DST
- **Colombia: Drilling Under Way**
  - Kronos: Large 3-Way
  - Calasu: Multi-Target 4-Way
  - Grand Col Area: 3D Acquisition
- **Kenya**
  - Mlima: Large 4-Way
- **Mozambique**
  - Success at Tubarão Tigre



Leveraging Exploration as a Competitive Advantage

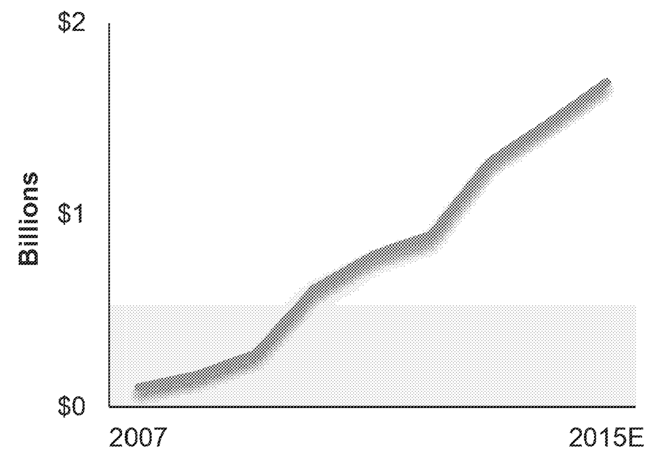
NYSE: APC | www.anadarko.com

- Capture with High Working Interest
- Perform Early Science
- Develop High-Quality Projects
- Leverage Reputation
- Ensure Win-Win Partnerships

$200+ Million Funding in 2014 → 25% Uplift in Activity

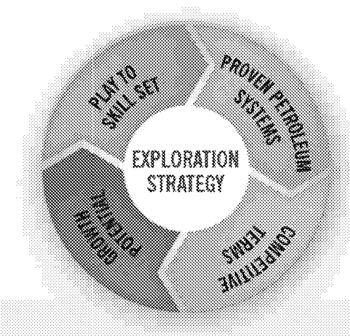
$200+ Million Funding in 2015 & Growing → 33+% Uplift in Activity

~$2 Billion Farm-Out Funding



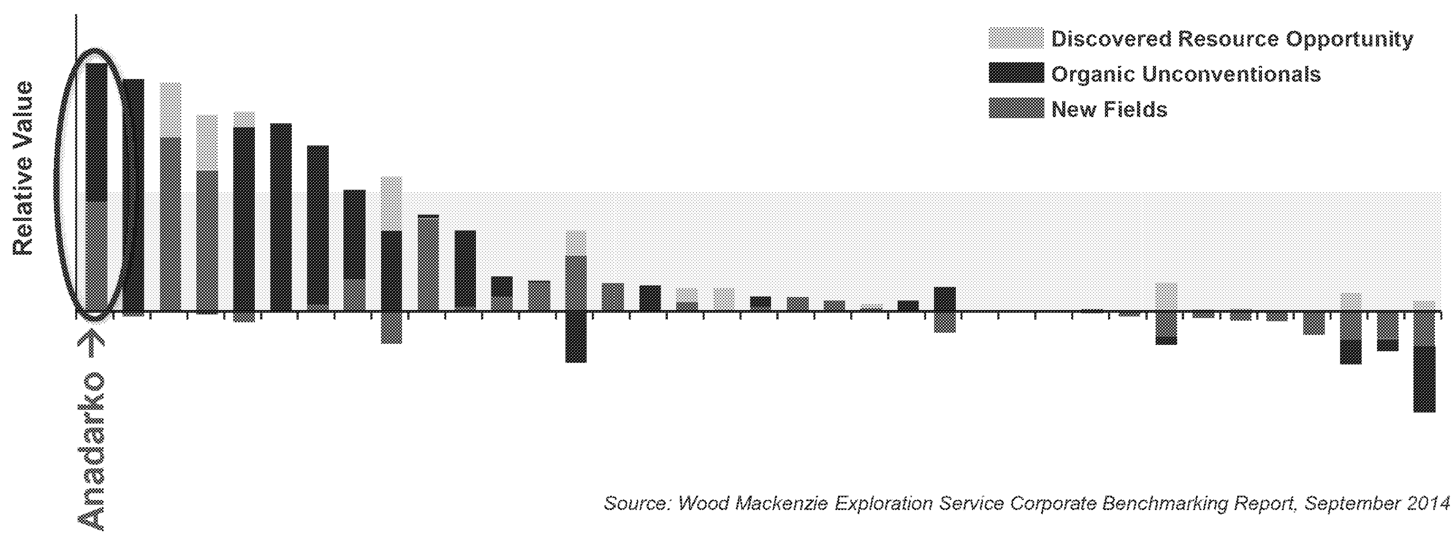
Proven Exploration Strategy with an Eye on the Future

NYSE: APC | www.anadarko.com



- Accelerating Portfolio Value
- Leveraging Our Success
- Providing Option Value

Value Creation from New Fields, Organic Unconventionals and DROs (2009 - 2013)



Source: Wood Mackenzie Exploration Service Corporate Benchmarking Report, September 2014

Preserving Value & Positioning for the Future

NYSE: APC | www.anadarko.com

- Balanced Portfolio with Unmatched Depth and Quality
- Demonstrated Commitment to Financial Discipline
- Efficient Capital-Allocation Approach
- Active Portfolio Management
- Sustained Focus on Long-Term Value Creation

Exhibit 92

Table of Contents

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D. C. 20549

FORM 10-Q

(Mark One)

[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended March 31, 2015

or

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from to

Commission File No. 1-8968

ANADARKO PETROLEUM CORPORATION
(Exact name of registrant as specified in its charter)

Delaware	**76-0146568**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

1201 Lake Robbins Drive, The Woodlands, Texas 77380-1046
(Address of principal executive offices)

Registrant's telephone number, including area code **(832) 636-1000**

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer," and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

The number of shares outstanding of the Company's common stock at April 27, 2015, is shown below:

Title of Class	Number of Shares Outstanding
Common Stock, par value $0.10 per share	507,935,794

TABLE OF CONTENTS

		Page
PART I		
Item 1.	Financial Statements	
	Consolidated Statements of Income for the Three Months Ended March 31, 2015 and 2014	2
	Consolidated Statements of Comprehensive Income for the Three Months Ended March 31, 2015 and 2014	3
	Consolidated Balance Sheets at March 31, 2015, and December 31, 2014	4
	Consolidated Statement of Equity for the Three Months Ended March 31, 2015	5
	Consolidated Statements of Cash Flows for the Three Months Ended March 31, 2015 and 2014	6
	Notes to Consolidated Financial Statements	7
Item 2.	Management's Discussion and Analysis of Financial Condition and Results of Operations	23
Item 3.	Quantitative and Qualitative Disclosures About Market Risk	41
Item 4.	Controls and Procedures	42
PART II		
Item 1.	Legal Proceedings	43
Item 1A.	Risk Factors	43
Item 2.	Unregistered Sales of Equity Securities and Use of Proceeds	43
Item 6.	Exhibits	44

Table of Contents

PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

ANADARKO PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF INCOME
(Unaudited)

millions except per-share amounts	Three Months Ended March 31, 2015	2014
Revenues and Other		
Natural-gas sales	$ 641	$ 1,217
Oil and condensate sales	1,419	2,424
Natural-gas liquids sales	232	386
Gathering, processing, and marketing sales	293	311
Gains (losses) on divestitures and other, net	(264)	1,506
Total	2,321	5,844
Costs and Expenses		
Oil and gas operating	296	313
Oil and gas transportation and other	361	266
Exploration	1,083	299
Gathering, processing, and marketing	254	252
General and administrative	310	298
Depreciation, depletion, and amortization	1,256	1,124
Other taxes	182	314
Impairments	2,783	3
Deepwater Horizon settlement and related costs	4	—
Total	6,529	2,869
Operating Income (Loss)	(4,208)	2,975
Other (Income) Expense		
Interest expense	216	183
(Gains) losses on derivatives, net	152	453
Other (income) expense, net	47	1
Tronox-related contingent loss	5	4,300
Total	420	4,937
Income (Loss) Before Income Taxes	(4,628)	(1,962)
Income tax expense (benefit)	(1,392)	664
Net Income (Loss)	(3,236)	(2,626)
Net income attributable to noncontrolling interests	32	43
Net Income (Loss) Attributable to Common Stockholders	$ (3,268)	$ (2,669)
Per Common Share		
Net income (loss) attributable to common stockholders—basic	$ (6.45)	$ (5.30)
Net income (loss) attributable to common stockholders—diluted	$ (6.45)	$ (5.30)
Average Number of Common Shares Outstanding—Basic	507	504
Average Number of Common Shares Outstanding—Diluted	507	504
Dividends (per common share)	$ 0.27	$ 0.18

See accompanying Notes to Consolidated Financial Statements.

Table of Contents

ANADARKO PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Unaudited)

millions	Three Months Ended March 31, 2015	2014
Net Income (Loss)	**$ (3,236)**	$ (2,626)
Other Comprehensive Income (Loss)		
Adjustments for derivative instruments		
Reclassification of previously deferred derivative losses to (gains) losses on derivatives, net	**2**	2
Income taxes on reclassification of previously deferred derivative losses to (gains) losses on derivatives, net	**(1)**	(1)
Total adjustments for derivative instruments, net of taxes	**1**	1
Adjustments for pension and other postretirement plans		
Amortization of net actuarial (gain) loss to general and administrative expense	**13**	7
Income taxes on amortization of net actuarial (gain) loss to general and administrative expense	**(4)**	(2)
Total adjustments for pension and other postretirement plans, net of taxes	**9**	5
Total	**10**	6
Comprehensive Income (Loss)	**(3,226)**	(2,620)
Comprehensive income attributable to noncontrolling interests	**32**	43
Comprehensive Income (Loss) Attributable to Common Stockholders	**$ (3,258)**	$ (2,663)

See accompanying Notes to Consolidated Financial Statements.

Table of Contents

ANADARKO PETROLEUM CORPORATION
CONSOLIDATED BALANCE SHEETS
(Unaudited)

millions	March 31, 2015	December 31, 2014
ASSETS		
Current Assets		
Cash and cash equivalents	$ 2,308	$ 7,369
Accounts receivable (net of allowance of $9 million and $7 million)		
Customers	1,025	1,118
Others	1,149	1,409
Other current assets	683	1,325
Total	5,165	11,221
Properties and Equipment		
Cost	76,040	75,107
Less accumulated depreciation, depletion, and amortization	37,770	33,518
Net properties and equipment	38,270	41,589
Other Assets	2,998	2,310
Goodwill and Other Intangible Assets	6,540	6,569
Total Assets	$ 52,973	$ 61,689
LIABILITIES AND EQUITY		
Current Liabilities		
Accounts payable	$ 3,252	$ 3,683
Current asset retirement obligations	282	257
Accrued expenses	1,100	994
Short-term debt	500	—
Deepwater Horizon settlement and related costs	94	90
Tronox-related contingent liability	—	5,210
Total	5,228	10,234
Long-term Debt	16,365	15,092
Other Long-term Liabilities		
Deferred income taxes	7,521	9,249
Asset retirement obligations	1,803	1,796
Other	3,122	3,000
Total	12,446	14,045
Equity		
Stockholders' equity		
Common stock, par value $0.10 per share (1.0 billion shares authorized, 527.6 million and 525.9 million shares issued)	52	52
Paid-in capital	9,045	9,005
Retained earnings	8,718	12,125
Treasury stock (19.7 million and 19.3 million shares)	(976)	(940)
Accumulated other comprehensive income (loss)	(507)	(517)
Total Stockholders' Equity	16,332	19,725
Noncontrolling interests	2,602	2,593
Total Equity	18,934	22,318

Total Liabilities and Equity	**$ 52,973**	$ 61,689

See accompanying Notes to Consolidated Financial Statements.

Table of Contents

ANADARKO PETROLEUM CORPORATION
CONSOLIDATED STATEMENT OF EQUITY
(Unaudited)

	Total Stockholders' Equity						
millions	Common Stock	Paid-in Capital	Retained Earnings	Treasury Stock	Accumulated Other Comprehensive Income (Loss)	Non-controlling Interests	Total Equity
Balance at December 31, 2014	$ 52	$ 9,005	$ 12,125	$ (940)	$ (517)	$ 2,593	$ 22,318
Net income (loss)	—	—	(3,268)	—	—	32	(3,236)
Common stock issued	—	50	—	—	—	—	50
Dividends—common stock	—	—	(139)	—	—	—	(139)
Repurchase of common stock	—	—	—	(36)	—	—	(36)
Subsidiary equity transactions	—	(10)	—	—	—	44	34
Distributions to noncontrolling interest owners	—	—	—	—	—	(67)	(67)
Reclassification of previously deferred derivative losses to (gains) losses on derivatives, net	—	—	—	—	1	—	1
Adjustments for pension and other postretirement plans	—	—	—	—	9	—	9
Balance at March 31, 2015	$ 52	$ 9,045	$ 8,718	$ (976)	$ (507)	$ 2,602	$ 18,934

See accompanying Notes to Consolidated Financial Statements.

Table of Contents

ANADARKO PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Three Months Ended March 31,	
millions	**2015**	2014
Cash Flows from Operating Activities		
Net income (loss)	**$ (3,236)**	$ (2,626)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities		
Depreciation, depletion, and amortization	**1,256**	1,124
Deferred income taxes	**(1,198)**	46
Dry hole expense and impairments of unproved properties	**1,009**	198
Impairments	**2,783**	3
(Gains) losses on divestitures, net	**334**	(1,459)
Total (gains) losses on derivatives, net	**152**	461
Operating portion of net cash received (paid) in settlement of derivative instruments	**91**	(98)
Other	**45**	54
Changes in assets and liabilities		
Deepwater Horizon settlement and related costs	**4**	—
Tronox-related contingent liability	**(5,210)**	4,300
(Increase) decrease in accounts receivable	**357**	(266)
Increase (decrease) in accounts payable and accrued expenses	**(283)**	(63)
Other items—net	**(608)**	55
Net cash provided by (used in) operating activities	**(4,504)**	1,729
Cash Flows from Investing Activities		
Additions to properties and equipment and dry hole costs	**(1,957)**	(2,501)
Acquisition of businesses	**—**	(4)
Divestitures of properties and equipment and other assets	**22**	3,257
Other—net	**10**	(170)
Net cash provided by (used in) investing activities	**(1,925)**	582
Cash Flows from Financing Activities		
Borrowings, net of issuance costs	**4,583**	918
Repayments of debt	**(2,830)**	(930)
Financing portion of net cash received (paid) for derivative instruments	**(146)**	—
Increase (decrease) in outstanding checks	**(39)**	97
Dividends paid	**(139)**	(92)
Repurchase of common stock	**(36)**	(35)
Issuance of common stock, including tax benefit on share-based compensation awards	**12**	13
Sale of subsidiary units	**31**	18
Distributions to noncontrolling interest owners	**(67)**	(51)
Net cash provided by (used in) financing activities	**1,369**	(62)
Effect of Exchange Rate Changes on Cash	**(1)**	(23)
Net Increase (Decrease) in Cash and Cash Equivalents	**(5,061)**	2,226
Cash and Cash Equivalents at Beginning of Period	**7,369**	3,698
Cash and Cash Equivalents at End of Period	**$ 2,308**	$ 5,924

See accompanying Notes to Consolidated Financial Statements.

Table of Contents

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

1. Summary of Significant Accounting Policies

General Anadarko Petroleum Corporation is engaged in the exploration, development, production, and marketing of natural gas, oil, condensate, natural gas liquids (NGLs), and anticipated production of liquefied natural gas (LNG). In addition, the Company engages in the gathering, processing, treating, and transporting of natural gas, oil, and NGLs. The Company also participates in the hard-minerals business through royalty arrangements. Unless the context otherwise requires, the terms "Anadarko" and "Company" refer to Anadarko Petroleum Corporation and its consolidated subsidiaries.

Basis of Presentation The information furnished herein reflects all normal recurring adjustments that are, in the opinion of management, necessary for the fair presentation of the Company's consolidated financial statements. Certain prior-period amounts have been reclassified to conform to the current-period presentation.

Use of Estimates The preparation of financial statements in accordance with generally accepted accounting principles in the United States requires management to make informed judgments and estimates that affect the reported amounts of assets, liabilities, revenues, and expenses. Management evaluates its estimates and related assumptions regularly, including those related to proved reserves; the value of properties and equipment; goodwill; intangible assets; asset retirement obligations; litigation liabilities; environmental liabilities; pension assets, liabilities, and costs; income taxes; and fair values. Changes in facts and circumstances or additional information may result in revised estimates, and actual results may differ from these estimates.

Recently Issued Accounting Standards The Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2015-02, *Consolidation—Amendments to the Consolidation Analysis*. This ASU will simplify existing requirements by reducing the number of consolidation models and placing more emphasis on risk of loss when determining a controlling financial interest. The provisions will affect how limited partnerships and similar entities are assessed for consolidation, including the elimination of the presumption that a general partner should consolidate a limited partnership. This ASU is effective for annual and interim periods beginning in 2016 and is required to be adopted using a retrospective or modified retrospective approach, with early adoption permitted. The Company is evaluating the impact of the adoption of this ASU on its consolidated financial statements.

The FASB issued ASU 2014-09, *Revenue from Contracts with Customers*. This ASU supersedes the revenue recognition requirements in Topic 605, *Revenue Recognition*, and industry-specific guidance in Subtopic 932-605, *Extractive Activities—Oil and Gas—Revenue Recognition*, and requires an entity to recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration the entity expects to be entitled to in exchange for those goods or services. This ASU is effective for annual and interim periods beginning in 2017 and is required to be adopted using one of two retrospective application methods, with no early adoption permitted. The Company is evaluating the impact of the adoption of this ASU on its consolidated financial statements.

2. Acquisitions, Divestitures, and Assets Held for Sale

In November 2014, Western Gas Partners, LP (WES) acquired Nuevo Midstream, LLC (Nuevo) for $1.554 billion. Following the acquisition, WES changed the name of Nuevo to Delaware Basin Midstream, LLC (DBM). The acquisition constitutes a business combination and was accounted for using the acquisition method of accounting. The fair-value measurements of the assets acquired and liabilities assumed at the acquisition date were still preliminary as of March 31, 2015, pending final review of support related to the acquired entity's assets. There were no material changes to the fair value of assets acquired and liabilities assumed from the amounts included on the Company's Consolidated Balance Sheet at December 31, 2014.

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

2. Acquisitions, Divestitures, and Assets Held for Sale (Continued)

For the three months ended March 31, 2015, the Company recognized net losses on divestitures of $334 million related to assets included in the oil and gas exploration and production reporting segment. During the first quarter of 2015, certain U.S. onshore assets in the Rocky Mountains Region (Rockies) satisfied criteria to be considered held for sale. These assets were remeasured to their current fair value using a market approach and Level 2 fair-value measurement, and the Company recognized a loss of $340 million. Gains and losses on assets held for sale are included in gains (losses) on divestitures and other, net in the Company's Consolidated Statements of Income. At March 31, 2015, the Company's Consolidated Balance Sheet included current assets of $29 million, long-term assets of $743 million, current liabilities of $17 million, and long-term liabilities of $78 million associated with assets held for sale. The sale of these assets closed in April 2015 for proceeds of $703 million.

3. Inventories

The following summarizes the major classes of inventories included in other current assets:

millions	**March 31, 2015**	December 31, 2014
Oil	**$ 97**	$ 133
Natural gas	**3**	27
NGLs	**70**	83
Total inventories	**$ 170**	$ 243

4. Impairments

The following summarizes impairments of proved properties and the related post-impairment fair values by segment:

	Three Months Ended	
millions	**Impairment**	**Fair Value (1)**
March 31, 2015		
Oil and gas exploration and production		
Long-lived assets held for use		
U.S. onshore properties	**$ 2,307**	**$ 1,299**
Midstream		
Long-lived assets held for use	**476**	**206**
Total	**$ 2,783**	**$ 1,505**
March 31, 2014		
Oil and gas exploration and production		
Cost-method investment (2)	$ 1	$ 32
Midstream		
Long-lived assets held for use	2	—
Total	$ 3	$ 32

(1) Measured using the income approach and Level 3 inputs.
(2) Represents the after-tax net investment.

Impairments during the first quarter of 2015 were primarily related to the Company's Greater Natural Buttes oil and gas and midstream properties in the Rockies, which were impaired due to lower commodity prices. Impairments of proved properties are included in impairment expense in the Company's Consolidated Statements of Income. In addition to the proved property impairments above, the Company also recognized a $935 million impairment of unproved Greater Natural Buttes properties as a result of lower commodity prices during the first quarter of 2015. Impairments of unproved properties are included in exploration expense in the

Company's Consolidated Statements of Income.

Table of Contents

5. Suspended Exploratory Well Costs

The Company's suspended exploratory well costs were $1.6 billion at March 31, 2015, and $1.5 billion at December 31, 2014. Projects with suspended exploratory well costs are those identified by management as exhibiting sufficient quantities of hydrocarbons to justify potential development and where management is actively pursuing efforts to assess whether reserves can be attributed to these projects. If additional information becomes available that raises substantial doubt as to the economic or operational viability of any of these projects, the associated costs will be expensed at that time. During the three months ended March 31, 2015, no exploratory well costs previously capitalized as suspended exploratory well costs for greater than one year at December 31, 2014, were charged to dry hole expense.

6. Noncontrolling Interests

Western Gas Equity Partners, LP (WGP) is a publicly traded consolidated subsidiary that owns partnership interests in WES. At March 31, 2015, Anadarko's ownership interest in WGP consisted of an 88.3% limited partner interest and the entire non-economic general partner interest. The remaining 11.7% limited partner interest in WGP was owned by the public.

WES, a publicly traded consolidated subsidiary, is a limited partnership that acquires, owns, develops, and operates midstream assets. During the three months ended March 31, 2015, WES issued 480 thousand common units to the public under its continuous offering program, raising net proceeds of $31 million. In 2014, WES issued 11 million Class C units to Anadarko to partially fund the acquisition of DBM. These Class C units receive distributions in the form of additional Class C units until the end of 2017 unless WES elects to convert the units earlier or Anadarko extends the conversion date. During the three months ended March 31, 2015, WES distributed 46 thousand Class C units to Anadarko. At March 31, 2015, WGP's ownership interest in WES consisted of a 34.8% limited partner interest, the entire 1.8% general partner interest, and all of the WES incentive distribution rights. At March 31, 2015, Anadarko also owned an 8.3% limited partner interest in WES through other subsidiaries' ownership of common and Class C units. The remaining 55.1% limited partner interest in WES was owned by the public.

7. Derivative Instruments

Objective and Strategy The Company uses derivative instruments to manage its exposure to cash-flow variability from commodity-price and interest-rate risks. Futures, swaps, and options are used to manage exposure to commodity-price risk inherent in the Company's oil and natural-gas production and natural-gas processing operations (Oil and Natural-Gas Production/Processing Derivative Activities). Futures contracts and commodity-price swap agreements are used to fix the price of expected future oil and natural-gas sales at major industry trading locations, such as Henry Hub, Louisiana, for natural gas and Cushing, Oklahoma, or Sullom Voe, Scotland, for oil. Basis swaps are periodically used to fix or float the price differential between product prices at one market location versus another. Options are used to establish a floor price, a ceiling price, or a floor and a ceiling price (collar) for expected future oil and natural-gas sales. Derivative instruments are also used to manage commodity-price risk inherent in customer price requirements and to fix margins on the future sale of natural gas and NGLs from the Company's leased storage facilities (Marketing and Trading Derivative Activities).

Interest-rate swaps are used to fix or float interest rates on existing or anticipated indebtedness. The purpose of these instruments is to manage the Company's existing or anticipated exposure to interest-rate changes. The fair value of the Company's current interest-rate swap portfolio increases (decreases) when interest rates increase (decrease).

The Company does not apply hedge accounting to any of its derivative instruments. As a result, gains and losses associated with derivative instruments are recognized currently in earnings. Net derivative losses attributable to derivatives previously subject to hedge accounting reside in accumulated other comprehensive income (loss) and are reclassified to earnings as the transactions to which the derivatives relate are recognized in earnings. See *Note 10—Accumulated Other Comprehensive Income (Loss)*.

7. Derivative Instruments (Continued)

Oil and Natural-Gas Production/Processing Derivative Activities The natural-gas prices listed below are New York Mercantile Exchange (NYMEX) Henry Hub prices. The following is a summary of the Company's derivative instruments related to natural-gas production/processing derivative activities at March 31, 2015:

		2015 Settlement
Natural Gas		
Three-Way Collars (thousand MMBtu/d)		635
Average price per MMBtu		
Ceiling sold price (call)	$	4.76
Floor purchased price (put)	$	3.75
Floor sold price (put)	$	2.75
Extendable Fixed-Price Contracts (thousand MMBtu/d) (1)		170
Average price per MMBtu	$	4.17

(1) The extendable fixed-price contracts have a contract term of January 2015 to December 2015 with an option for the counterparty to extend the contract term to December 2016 at the same price.
MMBtu—million British thermal units
MMBtu/d—million British thermal units per day

A three-way collar is a combination of three options: a sold call, a purchased put, and a sold put. The sold call establishes the maximum price that the Company will receive for the contracted commodity volumes. The purchased put establishes the minimum price that the Company will receive for the contracted volumes unless the market price for the commodity falls below the sold put strike price, at which point the minimum price equals the reference price (e.g., NYMEX) plus the excess of the purchased put strike price over the sold put strike price.

Marketing and Trading Derivative Activities The Company had financial derivative transactions with notional volumes of natural gas totaling 3 billion cubic feet (Bcf) at March 31, 2015, and 6 Bcf at December 31, 2014, that were entered into to mitigate commodity-price risk related to fixed-price purchase and sales contracts and storage activity.

Interest-Rate Derivatives Anadarko has outstanding interest-rate swap contracts to manage interest-rate risk associated with anticipated debt issuances. The Company has locked in a fixed interest rate in exchange for a floating interest rate indexed to the three-month London Interbank Offered Rate (LIBOR). These swap instruments include a provision that requires both the termination of the swaps and cash settlement in full at the start of the reference period.

Derivative settlements and collateralization are classified as cash flows from operating activities unless the derivatives contain an other-than-insignificant financing element, in which case the settlements and collateralization are classified as cash flows from financing activities. As a result of prior extensions of reference-period start dates without settlement of the related interest-rate derivative obligations, the interest-rate derivatives in the Company's portfolio contain an other-than-insignificant financing element and, therefore, any settlements or collateralization related to these extended interest-rate derivatives are classified as cash flows from financing activities.

The Company had the following outstanding interest-rate swaps at March 31, 2015:

millions except percentages		Reference Period		Weighted-Average
Notional Principal Amount		**Start**	**End**	**Interest Rate**
$	50	September 2016	September 2026	5.91%
$	1,850	September 2016	September 2046	6.06%

Table of Contents

7. Derivative Instruments (Continued)

Effect of Derivative Instruments—Balance Sheet The following summarizes the fair value of the Company's derivative instruments:

millions	Gross Derivative Assets		Gross Derivative Liabilities	
Balance Sheet Classification	**March 31, 2015**	December 31, 2014	**March 31, 2015**	December 31, 2014
Commodity derivatives				
Other current assets	**$ 351**	$ 421	**$ (86)**	$ (118)
Other assets	**35**	1	**—**	—
Accrued expenses	**65**	71	**(117)**	(114)
Other liabilities	**—**	—	**(31)**	(6)
	451	493	**(234)**	(238)
Interest-rate derivatives				
Other liabilities	**—**	—	**(1,422)**	(1,217)
Total derivatives	**$ 451**	$ 493	**$ (1,656)**	$ (1,455)

Effect of Derivative Instruments—Statement of Income The following summarizes gains and losses related to derivative instruments:

millions	Three Months Ended March 31,	
Classification of (Gain) Loss Recognized	**2015**	2014
Commodity derivatives		
Gathering, processing, and marketing sales (1)	**$ —**	$ 8
(Gains) losses on derivatives, net	**(53)**	215
Interest-rate derivatives		
(Gains) losses on derivatives, net	**205**	238
Total (gains) losses on derivatives, net	**$ 152**	$ 461

(1) Represents the effect of Marketing and Trading Derivative Activities.

Credit-Risk Considerations The financial integrity of exchange-traded contracts, which are subject to nominal credit risk, is assured by NYMEX or IntercontinentalExchange, Inc. through systems of financial safeguards and transaction guarantees. Over-the-counter traded swaps, options, and futures contracts expose the Company to counterparty credit risk. The Company monitors the creditworthiness of its counterparties, establishes credit limits according to the Company's credit policies and guidelines, and assesses the impact on fair value of its counterparties' creditworthiness. The Company has the ability to require cash collateral or letters of credit to mitigate its credit-risk exposure.

The Company has netting agreements with financial institutions that permit net settlement of gross commodity derivative assets against gross commodity derivative liabilities, and routinely exercises its contractual right to offset gains and losses when settling with derivative counterparties. In addition, the Company has setoff agreements with certain financial institutions that may be exercised in the event of default and provide for contract termination and net settlement across derivative types. At March 31, 2015, $237 million of the Company's $1.656 billion gross derivative liability balance, and at December 31, 2014, $289 million of the Company's $1.455 billion gross derivative liability balance would have been eligible for setoff against the Company's gross derivative asset balance in the event of default. Other than in the event of default, the Company does not net settle across derivative types.

Table of Contents

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

7. Derivative Instruments (Continued)

The Company's derivative instruments are subject to individually negotiated credit provisions that may require collateral of cash or letters of credit depending on the derivative's valuation versus negotiated credit thresholds. These credit thresholds may also require full or partial collateralization or immediate settlement of the Company's obligations if certain credit-risk-related provisions are triggered, such as if the Company's credit rating from major credit rating agencies declines to below investment grade. The aggregate fair value of derivative instruments with credit-risk-related contingent features for which a net liability position existed was $1.2 billion (net of collateral) at March 31, 2015, and $97 million (net of collateral) at December 31, 2014. The increase is primarily a result of additional derivative counterparties no longer maintaining secured positions under the Company's credit facilities and, therefore, the derivative instruments are now subject to credit-risk-related provisions. For information on the Company's revolving credit facilities, see *Note 8—Debt and Interest Expense—Anadarko Revolving Credit Facilities and Commercial Paper Program.*

Fair Value Valuations of physical-delivery purchase and sale agreements, over-the-counter financial swaps, and commodity option collars are based on similar transactions observable in active markets and industry-standard models that primarily rely on market-observable inputs. Inputs used to estimate fair value in industry-standard models are categorized as Level 2 inputs because substantially all assumptions and inputs are observable in active markets throughout the full term of the instruments. Inputs used to estimate the fair value of swaps and options include market-price curves; contract terms and prices; credit-risk adjustments; and, for Black-Scholes option valuations, discount factors and implied market volatility.

The following summarizes the fair value of the Company's derivative assets and liabilities, by input level within the fair-value hierarchy:

millions

March 31, 2015	Level 1	Level 2	Level 3	Netting (1)	Collateral	Total
Assets						
Commodity derivatives						
Financial institutions	**$ —**	**$ 431**	**$ —**	**$ (151)**	**$ (4)**	**$ 276**
Other counterparties	**—**	**20**	**—**	**—**	**—**	**20**
Total derivative assets	**$ —**	**$ 451**	**$ —**	**$ (151)**	**$ (4)**	**$ 296**
Liabilities						
Commodity derivatives						
Financial institutions	**$ —**	**$ (183)**	**$ —**	**$ 151**	**$ 1**	**$ (31)**
Other counterparties	**—**	**(51)**	**—**	**—**	**—**	**(51)**
Interest-rate derivatives	**—**	**(1,422)**	**—**	**—**	**169**	**(1,253)**
Total derivative liabilities	**$ —**	**$ (1,656)**	**$ —**	**$ 151**	**$ 170**	**$ (1,335)**
December 31, 2014						
Assets						
Commodity derivatives						
Financial institutions	$ —	$ 471	$ —	$ (187)	$ (13)	$ 271
Other counterparties	—	22	—	(2)	—	20
Total derivative assets	$ —	$ 493	$ —	$ (189)	$ (13)	$ 291
Liabilities						
Commodity derivatives						
Financial institutions	$ —	$ (234)	$ —	$ 187	$ —	$ (47)
Other counterparties	—	(4)	—	2	—	(2)
Interest-rate derivatives	—	(1,217)	—	—	23	(1,194)
Total derivative liabilities	$ —	$ (1,455)	$ —	$ 189	$ 23	$ (1,243)

(1) Represents the impact of netting commodity derivative assets and liabilities with counterparties where the Company has the contractual right and intends to net settle.

Table of Contents

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

8. Debt and Interest Expense

Debt The Company's outstanding debt is senior unsecured. The following summarizes the Company's outstanding debt:

millions	March 31, 2015	December 31, 2014
Total debt at face value	**$ 18,450**	$ 16,687
Net unamortized discounts and premiums (1)	**(1,606)**	(1,616)
Total borrowings	**$ 16,844**	$ 15,071
Capital lease obligation	**21**	21
Less short-term debt	**500**	—
Total long-term debt	**$ 16,365**	$ 15,092

(1) Unamortized discounts and premiums are amortized over the term of the related debt.

Anadarko's Zero-Coupon Senior Notes due 2036 (Zero Coupons) can be put to the Company in October of each year, in whole or in part, for the then-accreted value, which will be $796 million at the next put date in October 2015. Anadarko's Zero Coupons are classified as long-term debt on the Company's Consolidated Balance Sheets, as the Company has the ability and intent to refinance these obligations using long-term debt.

Fair Value The Company uses a market approach to determine fair value of its fixed-rate debt using observable market data, which results in a Level 2 fair-value measurement. The carrying amount of floating-rate debt approximates fair value as the variable interest rates are reflective of market rates. The estimated fair value of the Company's total borrowings was $19.3 billion at March 31, 2015, and $17.4 billion at December 31, 2014.

Debt Activity The following summarizes the Company's debt activity during the three months ended March 31, 2015:

millions	Carrying Value	Description
Balance at December 31, 2014	$ 15,071	
Borrowings	**1,500**	$5.0 billion revolving credit facility
	1,800	364-Day Facility
	140	WES revolving credit facility
	1,153	Commercial paper notes
Repayments	**(1,500)**	$5.0 billion revolving credit facility
	(1,300)	364-Day Facility
	(30)	WES revolving credit facility
Other, net	**10**	Amortization of debt discounts and premiums
Balance at March 31, 2015	**$ 16,844**	

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

8. Debt and Interest Expense (Continued)

Anadarko Revolving Credit Facilities and Commercial Paper Program In January 2015, upon satisfaction of certain conditions, including the settlement payment related to the Tronox Adversary Proceeding, the Company's $5.0 billion senior secured revolving credit facility was replaced by a $3.0 billion five-year senior unsecured revolving credit facility (Five-Year Facility), which is expandable to $4.0 billion, and a $2.0 billion 364-day senior unsecured revolving credit facility (364-Day Facility). For additional information, see *Note 11—Contingencies—Tronox Litigation*.

Borrowings under the Five-Year and 364-Day Facilities generally bear interest under one of two rate options, at Anadarko's election, using either LIBOR (or Euro Interbank Offered Rate in the case of borrowings under the Five-Year Facility denominated in Euro) or an alternate base rate, in each case plus an applicable margin ranging from 0.00% to 1.65% for the Five-Year Facility and 0.00% to 1.675% for the 364-Day Facility. The applicable margin will vary depending on Anadarko's credit ratings.

The Five-Year and 364-Day Facilities contain certain customary affirmative and negative covenants, including a financial covenant requiring maintenance of a consolidated indebtedness to total capitalization ratio of no greater than 65% and limitations on certain secured indebtedness, sale-and-leaseback transactions, and mergers and other fundamental changes. At March 31, 2015, the Company was in compliance with all covenants contained in its Five-Year and 364-Day Facilities.

At March 31, 2015, the Company had no outstanding borrowings under the Five-Year Facility and had $500 million of outstanding borrowings under its 364-Day Facility at an interest rate of 1.29%. The Company had available borrowing capacity of $1.5 billion under its 364-Day Facility.

During the first quarter of 2015, the Company initiated a commercial paper program, which allows a maximum of $3.0 billion of unsecured commercial paper notes and is supported by the Company's Five-Year Facility. The maturities of the commercial paper notes vary, but may not exceed 397 days. The commercial paper notes are sold under customary terms in the commercial paper market and are issued either at a discounted price to their principal face value or will bear interest at varying interest rates on a fixed or floating basis. Such discounted price or interest amounts are dependent on market conditions and the ratings assigned to the commercial paper program by credit rating agencies at the time of issuance of the commercial paper notes. At March 31, 2015, the Company had $1.2 billion of commercial paper notes outstanding at a weighted-average interest rate of 0.67%. The Company classified the outstanding commercial paper notes as long-term debt on the Company's Consolidated Balance Sheet, as the Company currently intends to refinance these obligations at maturity with additional commercial paper notes supported by the Company's Five-Year Facility.

WES Borrowings At March 31, 2015, WES was in compliance with all covenants contained in its five-year $1.2 billion senior unsecured revolving credit facility maturing in February 2019 (RCF), which is expandable to $1.5 billion. At March 31, 2015, WES had outstanding borrowings under its RCF of $620 million at an interest rate of 1.48%, had outstanding letters of credit of $13 million, and had available borrowing capacity of $567 million.

Interest Expense The following summarizes interest expense:

	Three Months Ended March 31,	
millions	**2015**	2014
Debt and other	**$ 254**	$ 240
Capitalized interest	**(38)**	(57)
Total interest expense	**$ 216**	$ 183

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Table of Contents

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

9. Stockholders' Equity

The following provides a reconciliation between basic and diluted earnings per share attributable to common stockholders:

millions except per-share amounts	Three Months Ended March 31, 2015		Three Months Ended March 31, 2014	
Net income (loss)				
Net income (loss) attributable to common stockholders	**$**	**(3,268)**	$	(2,669)
Less distributions on participating securities		**1**		—
Basic	**$**	**(3,269)**	$	(2,669)
Diluted	**$**	**(3,269)**	$	(2,669)
Shares				
Average number of common shares outstanding—basic		**507**		504
Average number of common shares outstanding—diluted		**507**		504
Excluded (1)		**11**		11
Net income (loss) per common share				
Basic	**$**	**(6.45)**	$	(5.30)
Diluted	**$**	**(6.45)**	$	(5.30)
Dividends per common share	**$**	**0.27**	$	0.18

(1) Inclusion of certain shares would have had an anti-dilutive effect.

10. Accumulated Other Comprehensive Income (Loss)

The following summarizes the after-tax changes in the balances of accumulated other comprehensive income (loss):

millions	Interest-rate Derivatives Previously Subject to Hedge Accounting		Pension and Other Postretirement Plans		Total	
Balance at December 31, 2014	$	(48)	$	(469)	$	(517)
Reclassifications to Consolidated Statement of Income		**1**		**9**		**10**
Balance at March 31, 2015	**$**	**(47)**	**$**	**(460)**	**$**	**(507)**

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

11. Contingencies

Litigation The Company is a defendant in a number of lawsuits, is involved in governmental proceedings, and is subject to regulatory controls arising in the ordinary course of business, including, but not limited to, personal injury claims; property damage claims; title disputes; tax disputes; royalty claims; contract claims; contamination claims relating to oil and gas production, transportation, and processing; and environmental claims, including claims involving assets owned by acquired companies and claims involving assets previously sold to third parties and no longer a part of the Company's current operations. Anadarko is also subject to various environmental-remediation and reclamation obligations arising from federal, state, and local laws and regulations. While the ultimate outcome and impact on the Company cannot be predicted with certainty, after consideration of recorded expense and liability accruals, management believes that the resolution of pending proceedings will not have a material adverse effect on the Company's financial condition, results of operations, or cash flows.

The following is a discussion of any material developments in previously reported contingencies and any other material matters that have arisen since the filing of the Company's Annual Report on Form 10-K for the year ended December 31, 2014.

Tronox Litigation On April 3, 2014, Anadarko and Kerr-McGee Corporation and certain of its subsidiaries entered into a settlement agreement to resolve all claims asserted by Tronox Incorporated (Tronox) and certain of its affiliates, including claims for actual and constructive fraudulent conveyance (Adversary Proceeding), for $5.15 billion. In addition, the Company agreed to pay interest on that amount from April 3, 2014, through the payment of the settlement. In January 2015, the Company paid $5.2 billion after the settlement agreement became effective. For additional disclosure of the Tronox Adversary Proceeding, see *Note 17—Contingencies—Tronox Litigation* in the *Notes to Consolidated Financial Statements* included in the Company's Annual Report on Form 10-K for the year ended December 31, 2014.

Anadarko recognized Tronox-related contingent losses of $850 million in the fourth quarter of 2013 and $4.3 billion in the first quarter of 2014. In addition, Anadarko recognized settlement-related interest expense, included in Tronox-related contingent loss in the Company's Consolidated Statement of Income, of $60 million during the year ended December 31, 2014, and $5 million during the three months ended March 31, 2015. For information on the tax effects of the settlement agreement, see *Note 12—Income Taxes*.

Deepwater Horizon Events In April 2010, the Macondo well in the Gulf of Mexico blew out and an explosion occurred on the *Deepwater Horizon* drilling rig, resulting in an oil spill. The well was operated by BP Exploration and Production Inc. (BP) and Anadarko held a 25% nonoperated interest. In October 2011, the Company and BP entered into a settlement agreement relating to the Deepwater Horizon events (Settlement Agreement). Pursuant to the Settlement Agreement, the Company is fully indemnified by BP against all claims and damages arising under the Oil Pollution Act of 1990 (OPA), claims for natural resource damages (NRD) and assessment costs, and any claims arising under the Operating Agreement with BP. This indemnification is guaranteed by BP Corporation North America Inc. (BPCNA) and, in the event that the net worth of BPCNA declines below an agreed-upon amount, BP p.l.c. has agreed to become the sole guarantor. Under the Settlement Agreement, BP does not indemnify the Company against penalties and fines, punitive damages, shareholder derivative or securities laws claims, or certain other claims. The Company has not recorded a liability for any costs that are subject to indemnification by BP. For additional disclosure of the Deepwater Horizon events, the Company's Settlement Agreement with BP, environmental claims under OPA, NRD claims, potential penalties and fines, and civil litigation, see *Note 17—Contingencies—Deepwater Horizon Events* in the *Notes to Consolidated Financial Statements* included in the Company's Annual Report on Form 10-K for the year ended December 31, 2014.

Penalties and Fines In December 2010, the U.S. Department of Justice (DOJ), on behalf of the United States, filed a civil lawsuit in the U.S. District Court for the Eastern District of Louisiana in New Orleans, Louisiana (Louisiana District Court) against several parties, including the Company, seeking an assessment of civil penalties under the Clean Water Act (CWA) in an amount to be determined by the Louisiana District Court. In February 2012, the Louisiana District Court entered a declaratory judgment that, as a partial owner of the Macondo well, Anadarko is liable for civil penalties under Section 311 of the CWA. The declaratory judgment, which was affirmed in June 2014 by the U.S. Court of Appeals for the Fifth Circuit (Fifth Circuit), addresses liability only, and does not address the amount of any civil penalty. In March 2015, Anadarko filed a petition for a writ of certiorari with the U.S. Supreme Court appealing the Fifth Circuit's decision.

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

11. Contingencies (Continued)

Applicable accounting guidance requires the Company to accrue a liability if it is probable that a liability has been incurred and the amount of the liability can be reasonably estimated. The Louisiana District Court's declaratory judgment in February 2012 satisfies the requirement that a liability arising from the future assessment of a civil penalty against Anadarko is probable. In an effort to resolve this matter, the Company made a settlement offer to the DOJ in July 2014 of $90 million and recorded a contingent liability for this amount at June 30, 2014. The Company subsequently engaged in further discussions regarding settlement, but the parties have not been able to reach agreement on either the amount of, or the terms and conditions governing, a settlement. The Company's settlement offer of $90 million remains outstanding and the Company remains open to resolving the matter through settlement discussions. The Company believes that $90 million under a settlement scenario is a better estimate of loss at this time than any other amount. Based on the above accounting guidance, the Company's contingent liability for CWA penalties and fines remains $90 million at March 31, 2015. However, the Company may ultimately incur a liability related to CWA penalties in excess of the current accrued liability.

The actual amount of a CWA penalty is subject to uncertainty, including whether the Company will be able to reach a settlement with the DOJ or will await the Louisiana District Court's opinion. The CWA sets forth subjective criteria to be considered by the court in assessing the magnitude of any CWA penalty, including the degree of fault of the owner. For the Phase I and II trials (defined in *Civil Litigation Damage Claims* below) and again for the penalty phase trial in January 2015, the Louisiana District Court ruled that no evidence of Anadarko's alleged culpability or fault could be presented. In addition, in its Phase I Findings of Fact and Conclusions of Law (Phase I Findings and Conclusions), the Louisiana District Court did not allocate any fault to Anadarko. Given the subjective nature of the CWA criteria used to determine penalty assessments and the Louisiana District Court's prior rulings related to culpability and allocation of fault, the Company currently cannot reasonably estimate the amount of any such penalty to be assessed or determine a reasonable range of potential loss if the matter is resolved by the Louisiana District Court following trial. However, given the Company's lack of direct operational involvement in the event, the Louisiana District Court's rulings excluding any evidence of Anadarko's alleged culpability or fault, the Phase I Findings and Conclusions that did not allocate any fault to Anadarko, and the subjective criteria of the CWA, the Company believes that any CWA penalties assessed to it will not materially impact the Company's financial condition, results of operations, or cash flows.

Events or factors that could assist the Company in estimating the amount of settlement or potential civil penalty or a range of potential loss related to such penalty include (i) an assessment by the DOJ, (ii) a ruling by a court of competent jurisdiction, or (iii) substantive settlement negotiations between the Company and the DOJ.

As discussed below, numerous Deepwater Horizon event-related civil lawsuits have been filed against BP and other parties, including the Company. Certain state and local governments appealed, or provided indication of a likely appeal of, the Louisiana District Court's decision that only federal law, and not state law, applies to Deepwater Horizon event-related claims. If any appeal is successful, state and/or local laws and regulations could become sources of penalties or fines against the Company.

Civil Litigation Damage Claims Numerous Deepwater Horizon event-related civil lawsuits have been filed against BP and other parties, including the Company. This litigation has been consolidated into a federal Multidistrict Litigation (MDL) action pending before Judge Carl Barbier in the Louisiana District Court.

The first phase of the trial in the MDL (Phase I) commenced in February 2013. The issues tried in Phase I included the cause of the blowout and all related events leading up to April 22, 2010, the date the *Deepwater Horizon* sank, as well as allocation of fault. In September 2014, the Louisiana District Court issued its Phase I Findings and Conclusions. The Louisiana District Court found that BP and BP America Production Company (BPAP), Transocean Ltd. (Transocean), and Halliburton Energy Services, Inc. (Halliburton), but not Anadarko, are each liable under general maritime law for the blowout, explosion, and oil spill. The court determined that BP's and BPAP's conduct was reckless and that both Transocean's and Halliburton's conduct was negligent. The Louisiana District Court apportioned 67% of the fault to BP and BPAP, 30% to Transocean, and 3% to Halliburton. No fault was allocated to Anadarko. The plaintiffs and BP have appealed the Phase I Findings and Conclusions.

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

11. Contingencies (Continued)

The second phase of trial (Phase II) began in September 2013. The issues tried in Phase II included spill-source control and quantification of the spill for the period from April 20, 2010, until the well was capped. In January 2015, the Louisiana District Court issued its Phase II Findings of Fact and Conclusions of Law (Phase II Findings and Conclusions). The Louisiana District Court found that, for purposes of calculating the maximum possible civil penalty under the CWA, 3.19 million barrels of oil were discharged into the Gulf of Mexico. The United States has appealed the Phase II Findings and Conclusions.

The penalty phase of the trial began in January 2015. In March 2014, the Louisiana District Court ruled that no evidence of Anadarko's alleged culpability or fault could be presented during the penalty phase trial. The parties rested their case in February 2015, post-trial briefing concluded in April 2015, and the matter is pending before the Louisiana District Court. The trial included Anadarko, BP, and the United States, and will assess findings and penalties under the CWA.

Remaining Liability Outlook It is possible that the Company may recognize additional Deepwater Horizon event-related liabilities for potential fines and penalties and certain other claims not covered by the indemnification provisions of the Settlement Agreement; however, the Company does not believe that any potential liability attributable to the foregoing items, individually or in the aggregate, will have a material impact on the Company's financial condition, results of operations, or cash flows. This assessment takes into account certain qualitative factors, including the subjective and fault-based nature of CWA penalties, the Company's indemnification by BP against certain damage claims as discussed above and BP's creditworthiness.

Although the Company is fully indemnified by BP against OPA damage claims, NRD claims and assessment costs, and certain other potential liabilities, the Company may be required to recognize a liability for these amounts in advance of or in connection with recognizing a receivable from BP for the related indemnity payment. In all circumstances, however, the Company expects that any additional indemnified liability that may be recognized by the Company will be subsequently recovered from BP itself or through the guarantees of BPCNA or BP p.l.c.

The Company will continue to monitor the MDL and other legal proceedings discussed above, as well as federal investigations related to the Deepwater Horizon events. The Company cannot predict the nature of additional evidence that may be discovered during the course of legal proceedings or the timing of completion of any legal proceedings.

Environmental Matters Anadarko is also subject to various environmental-remediation and reclamation obligations arising from federal, state, and local laws and regulations. The Company continually monitors remediation and reclamation processes and adjusts its liability for these obligations as necessary.

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

12. Income Taxes

The following summarizes income tax expense (benefit) and effective tax rates:

	Three Months Ended March 31,			
millions except percentages	**2015**		2014	
Income tax expense (benefit)	**$**	**(1,392)**	$	664
Effective tax rate		**30%**		(34)%

The Company reported a loss before income taxes for the three months ended March 31, 2015 and 2014. As a result, items that ordinarily increase or decrease the tax rate will have the opposite effect.

The decrease from the 35% U.S. federal statutory rate for the three months ended March 31, 2015, was primarily attributable to net changes in uncertain tax positions, Algerian exceptional profits taxes, and the tax impact from foreign operations. The decrease from the 35% U.S. federal statutory rate for the three months ended March 31, 2014, was primarily attributable to net changes in uncertain tax positions related to the settlement agreement associated with the Tronox Adversary Proceeding, Algerian exceptional profits taxes, and the tax impact from foreign operations.

At March 31, 2015, the Company had recorded a $577 million tax benefit related to the Tronox settlement. This benefit was net of a $1.3 billion uncertain tax position due to the uncertainty related to the deductibility of the settlement payment. At March 31, 2015, $561 million of this net benefit was presented in other assets and the remainder was presented in deferred income taxes on the Company's Consolidated Balance Sheet. The Company is a participant in the U.S. Internal Revenue Service's (IRS) Compliance Assurance Process and has regular discussions with the IRS concerning the Company's tax positions. Depending on the outcome of such discussions, it is reasonably possible that the amount of the uncertain tax position related to the settlement could change, perhaps materially. See *Note 11—Contingencies—Tronox Litigation*.

At March 31, 2015, accrued expenses on the Company's Consolidated Balance Sheet included $388 million of accrued income taxes.

13. Supplemental Cash Flow Information

For the three months ended March 31, 2015, other items—net in the Company's Consolidated Statements of Cash Flows includes a $561 million current tax benefit associated with the Tronox settlement. The following summarizes cash paid (received) for interest and income taxes, as well as non-cash investing and financing activities:

	Three Months Ended March 31,			
millions	**2015**		2014	
Cash paid (received)				
Interest, net of amounts capitalized (1)	**$**	**1,532**	$	265
Income taxes, net of refunds		**(5)**		598
Non-cash investing activities				
Fair value of properties and equipment from non-cash transactions	**$**	**54**	$	—
Asset retirement cost additions		**63**		47
Accruals of property, plant, and equipment		**1,061**		1,544
Net liabilities assumed (divested) in acquisitions and divestitures		**19**		(25)
Non-cash investing and financing activities				
Floating production, storage, and offloading vessel construction period obligation	**$**	**18**	$	34

(1) Includes $1.2 billion of interest related to the Tronox settlement payment in 2015.

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

14. Segment Information

Anadarko's business segments are separately managed due to distinct operational differences and unique technology, distribution, and marketing requirements. The Company's three reporting segments are oil and gas exploration and production, midstream, and marketing. The oil and gas exploration and production segment explores for and produces natural gas, oil, condensate, and NGLs, and plans for the development and operation of the Company's LNG project in Mozambique. The midstream segment engages in gathering, processing, treating, and transporting Anadarko and third-party oil, natural-gas, and NGLs production. The midstream reporting segment consists of two operating segments, WES and other midstream, which are aggregated into one reporting segment due to similar financial and operating characteristics. The marketing segment sells much of Anadarko's oil, natural-gas, and NGLs production, as well as third-party purchased volumes.

To assess the performance of Anadarko's operating segments, the chief operating decision maker analyzes Adjusted EBITDAX. The Company defines Adjusted EBITDAX as income (loss) before income taxes; exploration expense; depreciation, depletion, and amortization (DD&A); impairments; interest expense; total (gains) losses on derivatives, net, less net cash from settlement of commodity derivatives; and certain items not related to the Company's normal operations, less net income attributable to noncontrolling interests. During the periods presented, items not related to the Company's normal operations included Deepwater Horizon settlement and related costs, Tronox-related contingent loss, and certain other nonoperating items included in other (income) expense, net. The Company's definition of Adjusted EBITDAX excludes exploration expense as it is not an indicator of operating efficiency for a given reporting period. However, exploration expense is monitored by management as part of costs incurred in exploration and development activities. Similarly, DD&A and impairments are excluded from Adjusted EBITDAX as a measure of segment operating performance because capital expenditures are evaluated at the time capital costs are incurred. Adjusted EBITDAX also excludes interest expense to allow for assessment of segment operating results without regard to Anadarko's financing methods or capital structure. Total (gains) losses on derivatives, net, less net cash from settlement of commodity derivatives are excluded from Adjusted EBITDAX because these (gains) losses are not considered a measure of asset operating performance. Finally, net income attributable to noncontrolling interests is excluded from the Company's measure of Adjusted EBITDAX because it represents earnings that are not attributable to the Company's common stockholders.

Management believes that the presentation of Adjusted EBITDAX provides information useful in assessing the Company's financial condition and results of operations and that Adjusted EBITDAX is a widely accepted financial indicator of a company's ability to incur and service debt, fund capital expenditures, and make distributions to stockholders. Adjusted EBITDAX as defined by Anadarko may not be comparable to similarly titled measures used by other companies and should be considered in conjunction with net income (loss) attributable to common stockholders and other performance measures, such as operating income or cash flows from operating activities. Below is a reconciliation of consolidated Adjusted EBITDAX to income (loss) before income taxes:

	Three Months Ended March 31,	
millions	**2015**	2014
Income (loss) before income taxes	**$ (4,628)**	$ (1,962)
Exploration expense	**1,083**	299
DD&A	**1,256**	1,124
Impairments	**2,783**	3
Interest expense	**216**	183
Total (gains) losses on derivatives, net, less net cash from settlement of commodity derivatives	**243**	363
Deepwater Horizon settlement and related costs	**4**	—
Tronox-related contingent loss	**5**	4,300
Certain other nonoperating items	**22**	—
Less net income attributable to noncontrolling interests	**32**	43
Consolidated Adjusted EBITDAX	**$ 952**	$ 4,267

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

14. Segment Information (Continued)

Information presented below as "Other and Intersegment Eliminations" includes corporate costs, results from hard-minerals royalties, and net cash from settlement of commodity derivatives. The following summarizes selected financial information for Anadarko's reporting segments:

millions	Oil and Gas Exploration & Production	Midstream	Marketing	Other and Intersegment Eliminations	Total
Three Months Ended March 31, 2015					
Sales revenues	**$ 1,070**	**$ 174**	**$ 1,341**	**$ —**	**$ 2,585**
Intersegment revenues	**1,117**	**302**	**(1,191)**	**(228)**	**—**
Gains (losses) on divestitures and other, net	**(338)**	**—**	**—**	**74**	**(264)**
Total revenues and other	**1,849**	**476**	**150**	**(154)**	**2,321**
Operating costs and expenses [1]	**1,002**	**240**	**198**	**(37)**	**1,403**
Net cash from settlement of commodity derivatives	**—**	**—**	**—**	**(90)**	**(90)**
Other (income) expense, net [2]	**—**	**—**	**—**	**25**	**25**
Net income attributable to noncontrolling interests	**—**	**32**	**—**	**—**	**32**
Total expenses and other	**1,002**	**272**	**198**	**(102)**	**1,370**
Total (gains) losses on derivatives, net included in marketing revenue, less net cash from settlement	**—**	**—**	**1**	**—**	**1**
Adjusted EBITDAX	**$ 847**	**$ 204**	**$ (47)**	**$ (52)**	**$ 952**
Three Months Ended March 31, 2014					
Sales revenues	$ 2,389	$ 120	$ 1,829	$ —	$ 4,338
Intersegment revenues	1,553	320	(1,689)	(184)	—
Gains (losses) on divestitures and other, net	1,460	(2)	—	48	1,506
Total revenues and other	5,402	438	140	(136)	5,844
Operating costs and expenses [1]	1,012	232	181	18	1,443
Net cash from settlement of commodity derivatives	—	—	—	92	92
Other (income) expense, net	—	—	—	1	1
Net income attributable to noncontrolling interests	—	43	—	—	43
Total expenses and other	1,012	275	181	111	1,579
Total (gains) losses on derivatives, net included in marketing revenue, less net cash from settlement	—	—	2	—	2
Adjusted EBITDAX	$ 4,390	$ 163	$ (39)	$ (247)	$ 4,267

(1) Operating costs and expenses excludes exploration expense, DD&A, impairments, and Deepwater Horizon settlement and related costs since these expenses are excluded from Adjusted EBITDAX.

(2) Other (income) expense, net excludes certain other nonoperating items since these items are excluded from Adjusted EBITDAX.

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

15. Pension Plans and Other Postretirement Benefits

The Company has contributory and non-contributory defined-benefit pension plans, which include both qualified and supplemental plans. The Company also provides certain health care and life insurance benefits for certain retired employees. Retiree health care benefits are funded by contributions from the retiree, and in certain circumstances, contributions from the Company. The Company's retiree life insurance plan is noncontributory. The following summarizes the Company's pension and other postretirement benefit cost:

	Pension Benefits		Other Benefits	
millions	**2015**	2014	**2015**	2014
Three Months Ended March 31				
Service cost	**$ 30**	$ 25	**$ 3**	$ 2
Interest cost	**25**	25	**4**	4
Expected return on plan assets	**(27)**	(27)	**—**	—
Amortization of net actuarial loss (gain)	**13**	9	**—**	(2)
Net periodic benefit cost	**$ 41**	$ 32	**$ 7**	$ 4

Table of Contents

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

Unless the context otherwise requires, the terms "Anadarko" and "Company" refer to Anadarko Petroleum Corporation and its consolidated subsidiaries. The Company has made in this report, and may from time to time make in other public filings, press releases, and management discussions, forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended, concerning the Company's operations, economic performance, and financial condition. These forward-looking statements include, among other things, information concerning future production and reserves, schedules, plans, timing of development, contributions from oil and gas properties, marketing and midstream activities, and also include those statements preceded by, followed by, or that otherwise include the words "may," "could," "believes," "expects," "anticipates," "intends," "estimates," "projects," "target," "goal," "plans," "objective," "should," "would," "will," "potential," "continue," "forecast," "future," "likely," "outlook," or similar expressions or variations on such expressions. For such statements, the Company claims the protection of the safe harbor for forward-looking statements contained in the Private Securities Litigation Reform Act of 1995. Although the Company believes that the expectations reflected in such forward-looking statements are reasonable, it can give no assurance that such expectations will be realized. Anadarko undertakes no obligation to publicly update or revise any forward-looking statements whether as a result of new information, future events, or otherwise.

These forward-looking statements involve risk and uncertainties. Important factors that could cause actual results to differ materially from the Company's expectations include, but are not limited to, the following risks and uncertainties:

- *the Company's assumptions about energy markets*
- *production and sales volume levels*
- *reserves levels*
- *operating results*
- *competitive conditions*
- *technology*
- *availability of capital resources, levels of capital expenditures, and other contractual obligations*
- *supply and demand for, the price of, and the commercialization and transporting of natural gas, oil, natural gas liquids (NGLs), and other products or services*
- *volatility in the commodity-futures market*
- *weather*
- *inflation*
- *availability of goods and services, including unexpected changes in costs*
- *drilling risks*
- *processing volumes and pipeline throughput*
- *general economic conditions nationally, internationally, or in the jurisdictions in which the Company or its subsidiaries are, or in the future may be, doing business*
- *the Company's inability to timely obtain or maintain permits or other governmental approvals, including those necessary for drilling and/or development projects*
- *legislative or regulatory changes, including changes relating to hydraulic fracturing; retroactive royalty or production tax regimes; deepwater drilling and permitting regulations; derivatives reform; changes in state, federal, and foreign income taxes; environmental regulation; environmental risks; and liability under federal, state, foreign, and local environmental laws and regulations*

- *the ability of BP Exploration & Production Inc. (BP) to meet its indemnification obligations to the Company for Deepwater Horizon events, including, among other things, damage claims arising under the Oil Pollution Act of 1990 (OPA), claims for natural resource damages (NRD) and associated damage-assessment costs, and any claims arising under the Operating Agreement (OA) for the Macondo well, as well as the ability of BP Corporation North America Inc. (BPCNA) and BP p.l.c. to satisfy their guarantees of such indemnification obligations*
- *the impact of remaining claims related to the Deepwater Horizon events, including, but not limited to, fines, penalties, and punitive damages against the Company, for which it is not indemnified by BP*
- *civil or political unrest or acts of terrorism in a region or country*
- *the creditworthiness and performance of the Company's counterparties, including financial institutions, operating partners, and other parties*
- *volatility in the securities, capital, or credit markets and related risks such as general credit, liquidity, and interest-rate risk*
- *the Company's ability to successfully monetize select assets, repay its debt, and the impact of changes in the Company's credit ratings*
- *disruptions in international oil, NGLs, and condensate cargo shipping activities*
- *physical, digital, internal, and external security breaches*
- *supply and demand, technological, political, governmental, and commercial conditions associated with long-term development and production projects in domestic and international locations*
- *other factors discussed below and elsewhere in "Risk Factors" and in "Management's Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Estimates" included in the Company's 2014 Annual Report on Form 10-K, this Form 10-Q, and in the Company's other public filings, press releases, and discussions with Company management*

The following discussion should be read together with the *Consolidated Financial Statements* and the *Notes to Consolidated Financial Statements*, which are included in this report in Part I, Item 1; the information set forth in *Risk Factors* under Part II, Item 1A; the *Consolidated Financial Statements* and the *Notes to Consolidated Financial Statements,* which are included in Part II, Item 8 of the 2014 Annual Report on Form 10-K; and the information set forth in the *Risk Factors* under Part I, Item 1A of the 2014 Annual Report on Form 10-K.

OVERVIEW

Anadarko is among the world's largest independent exploration and production companies. Anadarko is engaged in the exploration, development, production, and marketing of natural gas, oil, condensate, NGLs, and anticipated production of liquefied natural gas. The Company also engages in the gathering, processing, treating, and transporting of natural gas, oil, and NGLs. The Company has production and exploration activities worldwide, including activities in the United States, Mozambique, Algeria, Ghana, Brazil, Colombia, Côte d'Ivoire, Kenya, New Zealand, and other countries.

Significant operating and financial activities for the first quarter of 2015 include the following:

Overall

- Anadarko's first-quarter sales volumes averaged 934 thousand barrels of oil equivalent per day (MBOE/d), representing a 14% increase over the first quarter of 2014.
- Anadarko's first-quarter liquids sales volumes averaged 478 thousand barrels per day (MBbls/d), representing a 29% increase over the first quarter of 2014, primarily due to increased sales volumes from the Wattenberg field and the Eagleford shale, and the timing of cargo liftings in Algeria and Ghana.
- The Company paid $5.2 billion related to a settlement agreement to resolve all claims asserted in the Tronox Adversary Proceeding. See *Note 11—Contingencies—Tronox Litigation* in the *Notes to Consolidated Financial Statements* under Part I, Item 1 of this Form 10-Q.
- The Company's overall sales product mix increased to 51% liquids in the first quarter of 2015 compared to 45% in the first quarter of 2014.

U.S. Onshore

- U.S. onshore first-quarter sales volumes averaged 740 MBOE/d, representing a 17% increase over the first quarter of 2014, primarily due to increased sales volumes from the Wattenberg field and the Eagleford shale.
- The Company sold certain U.S. onshore oil and gas assets in the Rocky Mountains Region (Rockies) for $703 million in April 2015, recognizing a loss of $340 million in the first quarter of 2015.

Gulf of Mexico

- Gulf of Mexico first-quarter sales volumes averaged 89 MBOE/d, representing a 9% decrease from the first quarter of 2014, primarily due to natural-gas production declines at Independence Hub.
- Anadarko's Lucius development project in the deepwater Gulf of Mexico achieved first oil in January 2015.
- The Company participated in the successful drilling of the Yeti exploration well (37.5% working interest) in Walker Ridge Block 160 and the well was successfully sidetracked to test the down-dip limits of the field.

International

- International first-quarter sales volumes averaged 105 MBOE/d, representing a 16% increase from the first quarter of 2014, primarily due to the timing of cargo liftings in Algeria and Ghana.

Financial

- Anadarko's net loss attributable to common stockholders for the first quarter of 2015 totaled $3.3 billion, which included $3.7 billion of pretax expenses for proved and unproved property impairments related to the Company's Greater Natural Buttes properties in the Rockies.
- The Company's net cash used in operating activities was $4.5 billion, which included the $5.2 billion Tronox settlement payment. The Company ended the quarter with $2.3 billion of cash on hand.
- The Company initiated a commercial paper program, which allows a maximum of $3.0 billion of unsecured commercial paper notes. The Company had $1.2 billion of borrowings outstanding under this program at March 31, 2015.
- The Company replaced its $5.0 billion senior secured revolving credit facility with a $3.0 billion five-year senior unsecured revolving credit facility (Five-Year Facility), which is expandable to $4.0 billion, and a $2.0 billion 364-day senior unsecured revolving credit facility (364-Day Facility). The Company had $500 million of borrowings outstanding under the 364-Day Facility and no borrowings under the Five-Year Facility at March 31, 2015.

The following discussion pertains to Anadarko's results of operations, financial condition, and changes in financial condition. Any increases or decreases "for the three months ended March 31, 2015," refer to the comparison of the three months ended March 31, 2015, to the three months ended March 31, 2014. The primary factors that affect the Company's results of operations include commodity prices for natural gas, oil, and NGLs; sales volumes; the Company's ability to discover additional oil and natural-gas reserves; the cost of finding such reserves; and operating costs.

RESULTS OF OPERATIONS

	Three Months Ended March 31,	
millions except per-share amounts	**2015**	2014
Financial Results		
Revenues and other	**$ 2,321**	$ 5,844
Costs and expenses	**6,529**	2,869
Other (income) expense	**420**	4,937
Income tax expense (benefit)	**(1,392)**	664
Net income (loss) attributable to common stockholders	**$ (3,268)**	$ (2,669)
Net income (loss) per common share attributable to common stockholders—diluted	**$ (6.45)**	$ (5.30)
Average number of common shares outstanding—diluted	**507**	504
Operating Results		
Adjusted EBITDAX (1)	**$ 952**	$ 4,267
Sales volumes (MMBOE)	**84**	74

MMBOE—million barrels of oil equivalent

(1) See *Operating Results—Segment Analysis—Adjusted EBITDAX* for a description of Adjusted EBITDAX, which is not a U.S. Generally Accepted Accounting Principles (GAAP) measure, and for a reconciliation of Adjusted EBITDAX to income (loss) before income taxes, which is presented in accordance with GAAP.

Table of Contents

FINANCIAL RESULTS

Sales Revenues and Volumes

	Three Months Ended March 31,			
millions except percentages	Natural Gas	Oil and Condensate	NGLs	Total
2014 sales revenues	$ 1,217	$ 2,424	$ 386	$ 4,027
Changes associated with sales volumes	**19**	**568**	**173**	**760**
Changes associated with prices	**(595)**	**(1,573)**	**(327)**	**(2,495)**
2015 sales revenues	**$ 641**	**$ 1,419**	**$ 232**	**$ 2,292**
Increase (decrease) vs. 2014	**(47)%**	**(41)%**	**(40)%**	**(43)%**

Anadarko's sales revenues decreased for the three months ended March 31, 2015, due to lower average commodity prices, partially offset by higher sales volumes for all commodities.

	Three Months Ended March 31,		
Sales Volumes	**2015**	Inc/(Dec) vs. 2014	2014
Barrels of Oil Equivalent (MMBOE except percentages)			
United States	**75**	14%	66
International	**9**	16	8
Total barrels of oil equivalent	**84**	14	74
Barrels of Oil Equivalent per Day (MBOE/d except percentages)			
United States	**829**	14%	729
International	**105**	16	90
Total barrels of oil equivalent per day	**934**	14	819

Sales volumes represent actual production volumes adjusted for changes in commodity inventories and natural-gas production volumes provided to satisfy a commitment established in conjunction with a development plan. Anadarko employs marketing strategies to minimize market-related shut-ins, maximize realized prices, and manage credit-risk exposure. For additional information, see *Note 7—Derivative Instruments* in the *Notes to Consolidated Financial Statements* under Part I, Item 1 of this Form 10-Q and *Other (Income) Expense—(Gains) Losses on Derivatives, net.*

Table of Contents

Natural-Gas Sales Volumes, Average Prices, and Revenues

	Three Months Ended March 31,				
		2015	Inc/(Dec) vs. 2014		2014
United States					
Sales volumes—Bcf		**246**	2 %		243
MMcf/d		**2,738**	2		2,697
Price per Mcf	**$**	**2.60**	(48)	$	5.01
Natural-gas sales revenues (millions)	**$**	**641**	(47)	$	1,217

Bcf—billion cubic feet
MMcf/d—million cubic feet per day
Mcf—thousand cubic feet

The Company's natural-gas sales volumes increased by 41 MMcf/d for the three months ended March 31, 2015.

- Sales volumes in the Southern and Appalachia Region increased by 63 MMcf/d primarily as a result of continued horizontal drilling in the Eagleford shale.
- Sales volumes in the Rockies increased by 32 MMcf/d due to higher sales volumes in the Wattenberg field as a result of continued horizontal drilling. This increase was partially offset by the natural production declines at Greater Natural Buttes and the Powder River basin and the sale of the Company's Pinedale/Jonah assets in January 2014.
- Sales volumes in the Gulf of Mexico decreased by 54 MMcf/d primarily due to natural production declines at Independence Hub.

The average natural-gas price Anadarko received decreased for the three months ended March 31, 2015, primarily due to lower weather-driven residential and commercial demand year over year and strong production growth in the northeast United States.

Table of Contents

Oil and Condensate Sales Volumes, Average Prices, and Revenues

	Three Months Ended March 31,		
	2015	Inc/(Dec) vs. 2014	2014
United States			
Sales volumes—MMBbls	**22**	31 %	16
MBbls/d	**237**	31	180
Price per barrel	**$ 44.19**	(53)	$ 94.84
International			
Sales volumes—MMBbls	**8**	9 %	8
MBbls/d	**98**	9	90
Price per barrel	**$ 54.15**	(50)	$ 108.41
Total			
Sales volumes—MMBbls	**30**	23 %	24
MBbls/d	**335**	23	270
Price per barrel	**$ 47.12**	(53)	$ 99.37
Oil and condensate sales revenues (millions)	**$ 1,419**	(41)	$ 2,424

MMBbls—million barrels

Anadarko's oil and condensate sales volumes increased by 65 MBbls/d for the three months ended March 31, 2015.

- Sales volumes in the Rockies increased by 42 MBbls/d primarily in the Wattenberg field due to continued horizontal drilling.
- Southern and Appalachia Region sales volumes increased by 15 MBbls/d primarily as a result of continued horizontal drilling in the Eagleford shale.
- International sales volumes increased by 8 MBbls/d due to higher sales volumes in Ghana and Algeria due to the timing of cargo liftings, partially offset by lower sales volumes due to the sale of the Company's Chinese subsidiary in August 2014.
- Sales volumes in the Gulf of Mexico were relatively flat as sales volumes from the Lucius development, which achieved first oil in January 2015, were offset by natural production declines primarily at Marco Polo.

Anadarko's average oil price received decreased for the three months ended March 31, 2015, as a result of global oversupply and reduced oil demand.

Table of Contents

Natural-Gas Liquids Sales Volumes, Average Prices, and Revenues

	Three Months Ended March 31,		
	2015	Inc/ (Dec) vs. 2014	2014
United States			
Sales volumes—MMBbls	**12**	38 %	9
MBbls/d	**136**	38	99
Price per barrel	**$ 17.29**	(60)	$43.35
International			
Sales volumes—MMBbls	**1**	NM	—
MBbls/d	**7**	NM	—
Price per barrel	**$ 32.75**	NM	$ —
Total			
Sales volumes—MMBbls	**13**	45 %	9
MBbls/d	**143**	45	99
Price per barrel	**$ 18.00**	(58)	$43.35
Natural-gas liquids sales revenues (millions)	**232**	(40)	$ 386

NM—not meaningful

NGLs sales represent revenues from the sale of product derived from the processing of Anadarko's natural-gas production. The Company's NGLs sales volumes increased by 44 MBbls/d for the three months ended March 31, 2015.

- Sales volumes in the Rockies increased by 30 MBbls/d primarily in the Wattenberg field due to continued horizontal drilling and the Lancaster plant coming online in April 2014.
- Sales volumes in the Southern and Appalachia Region increased by 7 MBbls/d as a result of continued horizontal drilling in the Eagleford shale.
- International NGLs sales volumes commenced in the second quarter of 2014 from the Company's El Merk facility in Algeria, resulting in sales volumes of 7 MBbls/d for the three months ended March 31, 2015.

Anadarko's average NGLs price received decreased for the three months ended March 31, 2015, primarily due to decreased propane prices as a result of lower seasonal demand, higher NGLs production levels, and related declines in oil prices.

Gathering, Processing, and Marketing

	Three Months Ended March 31,		
millions except percentages	**2015**	Inc/(Dec) vs. 2014	2014
Gathering, processing, and marketing sales	**$ 293**	(6)%	$ 311
Gathering, processing, and marketing expense	**254**	1	252
Total gathering, processing, and marketing, net	**$ 39**	(34)	$ 59

Gathering and processing sales includes revenue from the sale of NGLs and remaining residue gas extracted from natural gas purchased from third parties and processed by Anadarko, as well as fee revenue earned by providing gathering, processing, compression, and treating services to third parties. Marketing sales include the margin earned from purchasing and selling third-party oil and natural gas. Gathering, processing, and marketing expense includes the cost of third-party natural gas purchased and processed by Anadarko, as well as other operating and transportation expenses related to the Company's costs to perform gathering, processing, and marketing activities.

Table of Contents

Gathering, processing, and marketing, net decreased by $20 million for the three months ended March 31, 2015, primarily resulting from lower processing revenue and lower marketing margins primarily due to decreased natural-gas and NGLs prices, partially offset by higher gathering revenue associated with increased volumes and by lower cost to purchase NGLs.

Gains (Losses) on Divestitures and Other, net

During the three months ended March 31, 2015, the Company recognized a loss of $340 million on assets held for sale. The loss was associated with the divestiture of certain U.S. onshore oil and gas assets in the Rockies, which closed in April 2015 for sales proceeds of $703 million. During the three months ended March 31, 2014, the Company recognized a $1.5 billion gain associated with its divestiture of a 10% working interest in Offshore Area 1 in Mozambique for sales proceeds of $2.64 billion.

Costs and Expenses

	Three Months Ended March 31,		
	2015	Inc/(Dec) vs. 2014	2014
Oil and gas operating (millions)	**$ 296**	(5)%	$ 313
Oil and gas operating—per BOE	**3.52**	(17)	4.24
Oil and gas transportation and other (millions)	**361**	36	266
Oil and gas transportation and other—per BOE	**4.29**	19	3.60

BOE—barrel of oil equivalent

For the three months ended March 31, 2015, oil and gas operating expense decreased by $17 million primarily due to lower workover costs in the Gulf of Mexico and the August 2014 sale of the Company's Chinese subsidiary, partially offset by higher costs associated with increased sales volumes in Ghana and Algeria. The related per BOE costs decreased by $0.72 primarily due to the lower costs and asset sale discussed above and increased sales volumes.

Oil and gas transportation and other expense increased by $95 million for the three months ended March 31, 2015, due to a $50 million expense for the early termination of a drilling rig and higher gas-gathering and transportation costs primarily attributable to higher volumes related to the growth in the Rockies. Oil and gas transportation and other expense per BOE increased by $0.69, including $0.59 related to the early termination of the drilling rig, as higher costs were only partially offset by increased sales volumes.

	Three Months Ended March 31,	
millions	**2015**	2014
Exploration Expense		
Dry hole expense	**$ 29**	$ 121
Impairments of unproved properties	**980**	77
Geological and geophysical expense	**22**	43
Exploration overhead and other	**52**	58
Total exploration expense	**$ 1,083**	$ 299

For the three months ended March 31, 2015, exploration expense increased by $784 million. Impairments of unproved properties increased by $903 million primarily due to a $935 million impairment in 2015 related to the Company's unproved Greater Natural Buttes properties as a result of lower commodity prices. This increase was partially offset by a $50 million impairment in 2014 due to the Company's decision not to pursue further drilling in Sierra Leone. Dry hole expense decreased by $92 million primarily due to unsuccessful drilling activities expensed in 2014 associated with wells in New Zealand and the Gulf of Mexico, compared to unsuccessful drilling activities expensed in 2015 associated with wells in Mozambique. Geological and geophysical expense decreased by $21 million due to lower seismic purchases in Côte d'Ivoire.

millions except percentages	Three Months Ended March 31, 2015	Inc/(Dec) vs. 2014	2014
General and administrative	**$ 310**	4 %	$ 298
Depreciation, depletion, and amortization	**1,256**	12	1,124
Other taxes	**182**	(42)	314
Impairments	**2,783**	NM	3

For the three months ended March 31, 2015, general and administrative expense increased by $12 million primarily due to higher employee-related expenses as a result of increased headcount.

Depreciation, depletion, and amortization (DD&A) expense increased by $132 million for the three months ended March 31, 2015, primarily due to higher sales volumes in 2015 and increased costs associated with additional gathering and processing facilities.

For the three months ended March 31, 2015, other taxes decreased by $132 million primarily due to lower U.S. severance taxes of $59 million, lower Algerian exceptional profits taxes of $33 million, and lower ad valorem taxes of $20 million. These decreases were primarily caused by lower commodity prices. Also, Chinese windfall profits taxes decreased by $19 million for the three months ended March 31, 2015, as a result of the sale of the Company's Chinese subsidiary in August 2014.

Impairment expense for the three months ended March 31, 2015, included $2.3 billion related to the Company's Greater Natural Buttes oil and gas properties and $445 million for related midstream properties, which were impaired due to lower commodity prices.

millions	Three Months Ended March 31, 2015	2014
Deepwater Horizon settlement and related costs	**$ 4**	$ —

Deepwater Horizon settlement and related costs for the three months ended March 31, 2015, included legal fees and other costs associated with the Deepwater Horizon event-related claims. For additional information, see *Note 11—Contingencies—Deepwater Horizon Events* in the *Notes to Consolidated Financial Statements* under Part I, Item 1 of this Form 10-Q.

Other (Income) Expense

millions except percentages	Three Months Ended March 31, 2015	2014
Interest Expense		
Debt and other	**$ 254**	$ 240
Capitalized interest	**(38)**	(57)
Total interest expense	**$ 216**	$ 183

Interest expense increased by $33 million for the three months ended March 31, 2015, primarily due to a decrease of $19 million in capitalized interest related to lower construction-in-progress balances for long-term capital projects and an increase of $7 million in interest expense due to higher debt outstanding during the three months ended March 31, 2015.

Table of Contents

millions		Three Months Ended March 31, 2015		2014
(Gains) Losses on Derivatives, net				
(Gains) losses on commodity derivatives, net	**$**	**(53)**	$	215
(Gains) losses on interest-rate derivatives, net		**205**		238
Total (gains) losses on derivatives, net	**$**	**152**	$	453

(Gains) losses on derivatives, net represents the changes in fair value of the Company's derivative instruments as a result of changes in commodity prices and interest rates. Anadarko enters into commodity derivatives to manage the risk of changes in the market prices for its anticipated sales of production. Anadarko also enters into interest-rate swaps to fix or float interest rates on existing or anticipated indebtedness to manage exposure to interest-rate changes. For additional information, see *Note 7—Derivative Instruments* in the *Notes to Consolidated Financial Statements* under Part I, Item 1 of this Form 10-Q.

millions		Three Months Ended March 31, 2015		2014
Other (Income) Expense, net				
Interest income	**$**	**(5)**	$	(3)
Other		**52**		4
Total other (income) expense, net	**$**	**47**	$	1

Other expense increased by $46 million for the three months ended March 31, 2015. Changes in foreign currency gains/losses of $29 million reflected the impact of exchange-rate changes primarily applicable to foreign currency held in escrow pending final determination of the Company's Brazilian tax liability attributable to the 2008 divestiture of the Peregrino field offshore Brazil. Also, as a result of a Chapter 11 bankruptcy declaration by a third party, the U.S. Department of the Interior ordered Anadarko to perform the decommissioning of a production facility and related wells, previously sold to the third party. The Company accrued the costs to decommission the facility and the wells in prior years. During the three months ended March 31, 2015, the Company recognized a charge of $22 million for the decommissioning of an additional well. Anadarko completed the decommissioning of the facility in 2014 and expects to complete the decommissioning of the wells in 2016.

millions		Three Months Ended March 31, 2015		2014
Tronox-related contingent loss	**$**	**5**	$	4,300

In April 2014, Anadarko and Kerr-McGee Corporation and certain of its subsidiaries (collectively, Kerr-McGee) entered into a settlement agreement for $5.15 billion, plus interest, resolving all claims asserted in the Tronox Adversary Proceeding. Anadarko recognized Tronox-related contingent losses of $4.3 billion during the three months ended March 31, 2014, and $850 million in 2013. During the three months ended March 31, 2015, Anadarko recognized settlement-related interest expense of $5 million. In January 2015, the Company paid $5.2 billion after the settlement agreement became effective. See *Note 11—Contingencies—Tronox Litigation* in the *Notes to Consolidated Financial Statements* under Part I, Item 1 of this Form 10-Q.

Table of Contents

Income Tax Expense

	Three Months Ended March 31,	
millions except percentages	**2015**	2014
Income tax expense (benefit)	**$ (1,392)**	$ 664
Effective tax rate	**30%**	(34)%

The Company reported a loss before income taxes for the three months ended March 31, 2015 and 2014. As a result, items that ordinarily increase or decrease the tax rate will have the opposite effect.

The decrease from the 35% U.S. federal statutory rate for the three months ended March 31, 2015, was primarily attributable to net changes in uncertain tax positions, Algerian exceptional profit taxes, and the tax impact from foreign operations. The decrease from the 35% U.S. federal statutory rate for the three months ended March 31, 2014, was primarily attributable to net changes in uncertain tax positions related to the settlement agreement associated with the Tronox Adversary Proceeding, Algerian exceptional profits taxes, and the tax impact from foreign operations.

For additional information on income taxes, see *Note 12—Income Taxes* in the *Notes to Consolidated Financial Statements* under Part I, Item 1 of this Form 10-Q.

Net Income Attributable to Noncontrolling Interests

The Company's net income attributable to noncontrolling interests for the three months ended March 31, 2015 and 2014, related to public ownership interests in Western Gas Partners, LP (WES) and Western Gas Equity Partners, LP (WGP). Public ownership in WES consisted of a 55.1% limited partnership interest at March 31, 2015, and 56.4% at March 31, 2014. Public ownership in WGP consisted of an 11.7% limited partnership interest at March 31, 2015, and 9.0% at March 31, 2014. See *Note 6—Noncontrolling Interests* in the *Notes to Consolidated Financial Statements* under Part I, Item 1 of this Form 10-Q.

OPERATING RESULTS

Segment Analysis—Adjusted EBITDAX To assess the performance of Anadarko's operating segments, the chief operating decision maker analyzes Adjusted EBITDAX. The Company defines Adjusted EBITDAX as income (loss) before income taxes; exploration expense; DD&A; impairments; interest expense; total (gains) losses on derivatives, net, less net cash from settlement of commodity derivatives; and certain items not related to the Company's normal operations, less net income attributable to noncontrolling interests. During the periods presented, items not related to the Company's normal operations included Deepwater Horizon settlement and related costs, Tronox-related contingent loss, and certain other nonoperating items included in other (income) expense, net. The Company's definition of Adjusted EBITDAX, which is not a GAAP measure, excludes exploration expense, as it is not an indicator of operating efficiency for a given reporting period. However, exploration expense is monitored by management as part of costs incurred in exploration and development activities. Similarly, DD&A and impairments are excluded from Adjusted EBITDAX as a measure of segment operating performance because capital expenditures are evaluated at the time capital costs are incurred. Adjusted EBITDAX also excludes interest expense to allow for assessment of segment operating results without regard to Anadarko's financing methods or capital structure. Total (gains) losses on derivatives, net, less net cash from settlement of commodity derivatives are excluded from Adjusted EBITDAX because these (gains) losses are not considered a measure of asset operating performance. Finally, net income attributable to noncontrolling interests is excluded from the Company's measure of Adjusted EBITDAX because it represents earnings that are not attributable to the Company's common stockholders.

Management believes that the presentation of Adjusted EBITDAX provides information useful in assessing the Company's financial condition and results of operations and that Adjusted EBITDAX is a widely accepted financial indicator of a company's ability to incur and service debt, fund capital expenditures, and make distributions to stockholders. Adjusted EBITDAX as defined by Anadarko may not be comparable to similarly titled measures used by other companies and should be considered in conjunction with net income (loss) attributable to common stockholders and other performance measures prepared in accordance with GAAP, such as operating income or cash flows from operating activities. Adjusted EBITDAX has important limitations as an analytical tool because it excludes certain items that affect net income (loss) attributable to common stockholders and net cash provided by operating activities. Adjusted EBITDAX should not be considered in isolation or as a substitute for an analysis of Anadarko's results as reported under GAAP. Below is a reconciliation of consolidated Adjusted EBITDAX to income (loss) before income taxes, and consolidated Adjusted EBITDAX by reporting segment.

Adjusted EBITDAX

millions except percentages	Three Months Ended March 31, 2015	Inc/(Dec) vs. 2014	2014
Income (loss) before income taxes	**$ (4,628)**	(136)%	$ (1,962)
Exploration expense	**1,083**	NM	299
DD&A	**1,256**	12	1,124
Impairments	**2,783**	NM	3
Interest expense	**216**	18	183
Total (gains) losses on derivatives, net, less net cash from settlement of commodity derivatives	**243**	(33)	363
Deepwater Horizon settlement and related costs	**4**	NM	—
Tronox-related contingent loss	**5**	(100)	4,300
Certain other nonoperating items	**22**	NM	—
Less net income attributable to noncontrolling interests	**32**	(26)	43
Consolidated Adjusted EBITDAX	**$ 952**	(78)	$ 4,267
Adjusted EBITDAX by reporting segment			
Oil and gas exploration and production	**$ 847**	(81)%	$ 4,390
Midstream	**204**	25	163
Marketing	**(47)**	(21)	(39)
Other and intersegment eliminations	**(52)**	79	(247)

Oil and Gas Exploration and Production Adjusted EBITDAX decreased for the three months ended March 31, 2015, primarily due to lower commodity prices, a $1.5 billion gain associated with the Company's 2014 divestiture of a 10% working interest in Offshore Area 1 in Mozambique, and a $340 million loss on assets held for sale associated with the divestiture of certain U.S. onshore oil and gas assets in the Rockies in April 2015. These decreases were partially offset by higher sales volumes for all commodities.

Midstream Adjusted EBITDAX increased for the three months ended March 31, 2015, primarily due to higher gathering revenue resulting from higher volumes.

Marketing Marketing earnings primarily represent the margin earned on sales of natural gas, oil, and NGLs purchased from third parties. Adjusted EBITDAX decreased for the three months ended March 31, 2015, due to lower marketing margins.

Other and Intersegment Eliminations Other and intersegment eliminations consist primarily of corporate costs, income from hard-minerals royalties, and net cash from settlement of commodity derivatives. Adjusted EBITDAX increased for the three months ended March 31, 2015, primarily due to an increase in net cash received for the settlement of commodity derivatives in 2015.

Table of Contents

LIQUIDITY AND CAPITAL RESOURCES

Overview Anadarko generates cash needed to fund capital expenditures, debt-service obligations, and dividend payments primarily from operating activities, and enters into debt and equity transactions primarily to maintain the Company's desired capital structure and to finance acquisition opportunities. The Company has a variety of funding sources available, including cash on hand, an asset portfolio that provides ongoing cash-flow-generating capacity, opportunities for liquidity enhancement through divestitures and joint-venture arrangements that reduce future capital expenditures, and the Company's credit facilities and commercial paper program. In addition, an effective registration statement is available to Anadarko covering the sale of WGP common units owned by the Company. Anadarko owned 34 million common units at March 31, 2015.

During the three months ended March 31, 2015, cash flows from operating activities and cash on hand were the primary sources for funding capital investments. The Company continuously monitors its liquidity needs, coordinates its capital expenditure program with its expected cash flows and projected debt-repayment schedule, and evaluates available funding alternatives in light of current and expected conditions.

At March 31, 2015, Anadarko had no scheduled debt maturities for the remainder of the year, other than $1.2 billion of borrowings under the commercial paper program. The Company classified the outstanding commercial paper notes as long-term debt on the Company's Consolidated Balance Sheet, as the Company currently intends to refinance these obligations at maturity with additional commercial paper notes supported by the Company's Five-Year Facility. Anadarko's Zero-Coupon Senior Notes due 2036 (Zero Coupons) can be put to the Company in October of each year, in whole or in part, for the then-accreted value, which will be $796 million at the next put date in October 2015. The Zero Coupons are classified as long-term debt on the Company's Consolidated Balance Sheets, as the Company has the ability and intent to refinance these obligations using long-term debt. Anadarko's scheduled 2016 debt maturities are $2.3 billion.

Management believes that the Company's liquidity position, asset portfolio, and operating and financial performance provide the necessary financial flexibility to fund the Company's current and long-term operations.

Revolving Credit Facilities and Commercial Paper Program In January 2015, upon satisfaction of certain conditions, including the settlement payment related to the Tronox Adversary Proceeding, the Company's $5.0 billion senior secured revolving credit facility was replaced by its Five-Year and 364-Day Facilities. Under these facilities, the Company's derivative counterparties no longer maintain security interests in any of the Company's assets. As a result, the Company may be required from time to time to post collateral of cash or letters of credit based on the negotiated terms of the individual derivative agreements.

Borrowings under the Five-Year and 364-Day Facilities generally bear interest under one of two rate options, at Anadarko's election, using either the London Interbank Offered Rate (LIBOR) (or Euro Interbank Offered Rate in the case of borrowings under the Five-Year Facility denominated in Euro) or an alternate base rate, in each case plus an applicable margin ranging from 0.00% to 1.65% for the Five-Year Facility and 0.00% to 1.675% for the 364-Day Facility. The applicable margin will vary depending on Anadarko's credit ratings.

The Five-Year and 364-Day Facilities contain certain customary affirmative and negative covenants, including a financial covenant requiring maintenance of a consolidated indebtedness to total capitalization ratio of no greater than 65%, and limitations on certain secured indebtedness, sale-and-leaseback transactions, and mergers and other fundamental changes. At March 31, 2015, the Company was in compliance with all covenants contained in its Five-Year and 364-Day Facilities.

At March 31, 2015, the Company had no outstanding borrowings under the Five-Year Facility and had $500 million of outstanding borrowings under its 364-Day Facility at an interest rate of 1.29%. The Company had available borrowing capacity of $1.5 billion under its 364-Day Facility.

During the first quarter of 2015, the Company initiated a commercial paper program, which allows a maximum of $3.0 billion of unsecured commercial paper notes and is supported by the Company's Five-Year Facility. The maturities of the commercial paper notes vary, but may not exceed 397 days. The commercial paper notes are sold under customary terms in the commercial paper market and are issued either at a discounted price to their principal face value or will bear interest at varying interest rates on a fixed or floating basis. Such discounted price or interest amounts are dependent on market conditions and the ratings assigned to the commercial paper program by credit rating agencies at the time of issuance of the commercial paper notes. At March 31, 2015, the Company had $1.2 billion of commercial paper notes outstanding at a weighted-average interest rate of 0.67%. During the three months ended March 31, 2015, the maximum outstanding under the commercial paper program was $1.4 billion. The average borrowings outstanding under the commercial paper program were $795 million with a weighted-average interest rate of 0.59%.

Table of Contents

WES Funding Sources Anadarko's consolidated subsidiary, WES, uses cash flows from operations to fund ongoing operations, service its debt, and make distributions to its equity holders. As needed, WES supplements cash generated from its operating activities with proceeds from debt or equity issuances or borrowings under its five-year $1.2 billion senior unsecured revolving credit facility maturing in February 2019 (RCF), which is expandable to $1.5 billion.

At March 31, 2015, WES was in compliance with all covenants contained in its RCF, had outstanding borrowings under its RCF of $620 million at an interest rate of 1.48%, had outstanding letters of credit of $13 million, and had available borrowing capacity of $567 million. See *Sources of Cash—Financing Activities* below.

During the three months ended March 31, 2015, WES issued 480 thousand common units to the public under its continuous offering program, which authorized the issuance of up to an aggregate of $500 million of common units, raising net proceeds of $31 million. The remaining amount available under this program was $469 million of common units at March 31, 2015.

Sources of Cash

Operating Activities Anadarko's cash flow used in operating activities during the three months ended March 31, 2015, was $4.5 billion, compared to cash flow provided by operating activities of $1.7 billion for the same period of 2014. The decrease is primarily due to the $5.2 billion Tronox settlement payment and decreased sales revenues resulting from lower commodity prices.

One of the primary sources of variability in the Company's cash flows from operating activities is fluctuations in commodity prices, the impact of which Anadarko partially mitigates by entering into commodity derivatives. Sales-volume changes also impact cash flow, but historically have not been as volatile as commodity prices. Anadarko's cash flows from operating activities are also impacted by the costs related to continuing operations and debt service.

Investing Activities During the three months ended March 31, 2015, Anadarko received pretax proceeds of $22 million primarily related to several property divestiture transactions.

Financing Activities During the three months ended March 31, 2015, the Company borrowed $1.8 billion under the 364-Day Facility, which was primarily used to repay $1.5 billion of borrowings entered into in January 2015 under its $5.0 billion senior secured revolving credit facility. The remaining proceeds were used for partial payment of the settlement related to the Tronox Adversary Proceeding and for general corporate purposes. The Company also borrowed $1.2 billion of commercial paper notes for general corporate purposes. Anadarko's consolidated subsidiary, WES, borrowed $140 million under its RCF primarily for general partnership purposes, including the funding of capital expenditures.

Uses of Cash

Anadarko invests significant capital to develop, acquire, and explore for oil and natural gas and to expand its midstream infrastructure. The Company also uses cash to fund ongoing operating costs, capital contributions for equity investments, debt repayments, and distributions to its shareholders.

Tronox Settlement Payment In April 2014, Anadarko and Kerr-McGee entered into a settlement agreement to resolve all claims asserted in the Tronox Adversary Proceeding for $5.15 billion. In addition, the Company agreed to pay interest on that amount from April 3, 2014, through payment of the settlement. In January 2015, the Company paid $5.2 billion after the settlement agreement became effective. See *Note 11—Contingencies—Tronox Litigation* in the *Notes to Consolidated Financial Statements* under Part I, Item 1 of this Form 10-Q.

Capital Expenditures The following presents the Company's capital expenditures by category:

	Three Months Ended March 31,	
millions	**2015**	2014
Property acquisitions		
Exploration	**$ 23**	$ 41
Development	**1**	106
Exploration	**207**	424
Development	**1,290**	1,573
Capitalized interest	**31**	49
Total oil and gas capital expenditures	**1,552**	2,193
Gathering, processing, and marketing and other (1)	**270**	375
Total capital expenditures (2)	**$ 1,822**	$ 2,568

(1) Includes WES capital expenditures of $156 million for the three months ended March 31, 2015, and $170 million for the three months ended March 31, 2014.

(2) Capital expenditures in this table are presented on an accrual basis. Additions to properties and equipment on the Company's Consolidated Statements of Cash Flows only include capital expenditures funded with cash payments during the period.

The Company's capital spending decreased by $746 million for the three months ended March 31, 2015, due to decreased development drilling of $283 million primarily in the Rockies and the Southern and Appalachia Region and lower exploration drilling of $217 million primarily in the Gulf of Mexico. Also, development acquisitions in 2014 included a spar lease buyout of $110 million in the Gulf of Mexico and gathering, processing, and marketing and other decreased $105 million primarily due to lower expenditures for plants and gathering in the Rockies.

In the third quarter of 2014, the Company entered into a carried-interest arrangement that requires a third party to fund $442 million of Anadarko's capital costs in exchange for a 34% working interest in the Eaglebine development, located in Southeast Texas. The third-party funding is expected to cover Anadarko's future capital costs in the development through 2016. At March 31, 2015, $36 million of the total $442 million obligation had been funded.

In the second quarter of 2013, the Company entered into a carried-interest arrangement that requires a third-party partner to fund $860 million of Anadarko's capital costs in exchange for a 12.75% working interest in the Heidelberg development, located in the Gulf of Mexico. The third-party funding is expected to cover the substantial majority of Anadarko's expected future capital costs through first production, which is expected to occur by mid-2016. At March 31, 2015, $490 million of the total $860 million obligation had been funded.

Investments During the three months ended March 31, 2015, the Company made capital contributions of $50 million for equity investments, which are included in Other—net under Investing Activities in the Consolidated Statements of Cash Flows. These contributions were primarily associated with joint ventures for a gas processing plant, marine well containment, and pipelines.

Debt Retirements and Repayments During the three months ended March 31, 2015, the Company repaid $1.5 billion of borrowings under the $5.0 billion senior secured revolving credit facility and $1.3 billion under the 364-Day Facility. WES also repaid $30 million of borrowings under its RCF.

Derivative Instruments The Company's derivative instruments are subject to individually negotiated credit provisions that may require the Company or the counterparties to provide collateral of cash or letters of credit depending on the derivative's valuation versus negotiated credit thresholds. These credit thresholds may also require full or partial collateralization or immediate settlement of the Company's obligations if certain credit-risk-related provisions are triggered, such as if the Company's credit rating from major credit rating agencies declines to below investment grade. The Company provided cash collateral of $170 million as of March 31, 2015, in connection with its derivative instruments.

Table of Contents

Common Stock Dividends and Distributions to Noncontrolling Interest Owners Anadarko paid dividends of $139 million to its common stockholders during the three months ended March 31, 2015, and $92 million during the three months ended March 31, 2014. During the second quarter of 2014, Anadarko increased the quarterly dividend paid to common stockholders from $0.18 per share to $0.27 per share. Anadarko has paid a dividend to its common stockholders on a quarterly basis since becoming a public company in 1986. The amount of future dividends paid to Anadarko common stockholders will be determined by the Board of Directors on a quarterly basis and will depend on earnings, financial condition, capital requirements, the effect a dividend payment would have on the Company's compliance with relevant financial covenants, and other factors.

WES distributed to its unitholders other than Anadarko and WGP an aggregate of $54 million during the three months ended March 31, 2015, and $41 million during the three months ended March 31, 2014. WES has made quarterly distributions to its unitholders since its initial public offering in the second quarter of 2008, and has increased its distribution from $0.30 per common unit for the third quarter of 2008 to $0.725 per common unit for the first quarter of 2015 (to be paid in May 2015).

WGP distributed to its unitholders other than Anadarko an aggregate of $8 million during the three months ended March 31, 2015, and $5 million during the three months ended March 31, 2014. WGP has made quarterly distributions to its unitholders since its initial public offering in December 2012, and has increased its distribution from $0.17875 per common unit for the first quarter of 2013 to $0.3125 per unit for the first quarter of 2015 (to be paid in May 2015).

Outlook

Oil, natural-gas, and NGLs prices can fluctuate significantly. The Company's revenues, operating results, cash flows from operations, capital spending, and future growth rates are highly dependent on the prices the Company receives for oil, natural gas, and NGLs. During the last 12 months, New York Mercantile Exchange West Texas Intermediate oil prices have been volatile and ranged from a high of $107.26 per barrel in June 2014 to a low of $43.46 in March 2015. The New York Mercantile Exchange Henry Hub natural-gas prices have also been volatile and ranged from a high of $4.83 per MMBtu in April 2014 to a low of $2.58 in February 2015. The duration and magnitude of the decline in oil and natural-gas prices cannot be predicted.

The Company has a deep portfolio of investment opportunities and the financial strength and operational flexibility to move capital spending from areas focused on near-term production growth to areas focused on longer-term growth where anticipated returns are less sensitive to spot oil and natural-gas prices. The recent decline in oil prices resulted in the Company significantly reducing its capital expenditures in 2015 compared to 2014. The Company will continue to evaluate the oil and natural-gas price environments and may adjust its capital spending plans as prices fluctuate while maintaining the appropriate liquidity and financial flexibility.

The Company is committed to the execution of its worldwide exploration, appraisal, and development programs. The Company estimates a 2015 capital spending range of $6.0 billion to $6.4 billion. This amount includes approximately $630 million to $690 million of WES capital expenditures, excluding any acquisitions made by WES. The Company currently plans to allocate approximately 65% of its 2015 capital spending to development activities, 15% to exploration activities, and 20% to gas-gathering and processing activities and other business activities. The Company currently expects its 2015 capital spending by area to be approximately 55% for the U.S. onshore region and Alaska, 10% for the Gulf of Mexico, 20% for Midstream and other, and 15% for International.

Anadarko believes that its cash on hand, available borrowing capacity, and expected level of operating cash flows will be sufficient to fund the Company's projected operational and capital programs for 2015 and continue to meet its other current obligations. The Company's cash on hand is available for use and could be supplemented, as needed, with available borrowing capacity under the 364-Day Facility, Five-Year Facility, and commercial paper program. The Company may also enter into carried-interest arrangements with third parties to fund certain capital expenditures, execute asset divestitures, and sell WGP common units that it owns in order to supplement cash flow.

The Company continuously monitors its liquidity needs, coordinates its capital expenditure program with its expected cash flows and projected debt-repayment schedule, and evaluates available funding alternatives in light of current and expected conditions. To reduce commodity-price risk and increase the predictability of 2015 cash flows, Anadarko entered into strategic derivative positions covering approximately 32% of its remaining 2015 anticipated natural-gas sales volumes. See *Note 7—Derivative Instruments* in the *Notes to Consolidated Financial Statements* under Part I, Item 1 of this Form 10-Q.

Recent Accounting Developments

See *Note 1—Summary of Significant Accounting Policies* in the *Notes to Consolidated Financial Statements* under Part I, Item 1 of this Form 10-Q.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

The Company's primary market risks are attributable to fluctuations in energy prices and interest rates. In addition, foreign-currency exchange-rate risk exists due to anticipated foreign-currency denominated payments and receipts. These risks can affect revenues and cash flows and the Company's risk-management policies provide for the use of derivative instruments to manage these risks. Both exchange and over-the-counter traded derivative instruments may be subject to margin-deposit requirements, and the Company may be required from time to time to deposit cash or provide letters of credit with exchange brokers or counterparties to satisfy these margin requirements. For additional information relating to the Company's derivative and financial instruments, see *Note 7—Derivative Instruments* in the *Notes to Consolidated Financial Statements* under Part I, Item 1 of this Form 10-Q.

COMMODITY-PRICE RISK The Company's most significant market risk relates to prices for natural gas, oil, and NGLs. Management expects energy prices to remain unpredictable and potentially volatile. As energy prices decline or rise significantly, revenues and cash flows are likewise affected. In addition, a non-cash write-down of the Company's oil and gas properties or goodwill may be required if commodity prices experience a significant decline. The types of commodity derivative instruments used by the Company include futures, swaps, options, and fixed-price physical-delivery contracts. The volume of commodity derivatives entered into by the Company is governed by risk-management policies and may vary from year to year. Below is a sensitivity analysis for the Company's commodity-price-related derivative instruments.

Derivative Instruments Held for Non-Trading Purposes The Company had derivative instruments in place to reduce the price risk associated with future production of 284 Bcf of natural gas at March 31, 2015, with a net derivative asset position of $204 million. Based on actual derivative contractual volumes, a 10% increase in underlying commodity prices would reduce the fair value of these derivatives by $37 million, while a 10% decrease in underlying commodity prices would increase the fair value of these derivatives by $30 million. However, any cash received or paid to settle these derivatives would be substantially offset by the sales value of production covered by the derivative instruments.

Derivative Instruments Held for Trading Purposes At March 31, 2015, the Company had a net derivative asset position of $13 million (gains of $13 million) on outstanding derivative instruments entered into for trading purposes. Based on actual derivative contractual volumes, a 10% increase or decrease in underlying commodity prices would not materially impact the Company's gains or losses on these derivative instruments.

INTEREST-RATE RISK Borrowings under each of the 364-Day Facility, the Five-Year Facility, and the WES RCF are subject to variable interest rates. The balance of Anadarko's long-term debt on the Company's Consolidated Balance Sheets is subject to fixed interest rates. The Company's $2.9 billion of LIBOR-based obligations, which are presented on the Company's Consolidated Balance Sheets net of preferred investments in two non-controlled entities, give rise to minimal net interest-rate risk because coupons on the related preferred investments are also LIBOR-based. While a 10% change in LIBOR would not materially impact the Company's interest cost, it would affect fair value of outstanding fixed-rate debt.

At March 31, 2015, the Company had a net derivative liability position of $1.4 billion related to interest-rate swaps. A 10% increase (decrease) in the three-month LIBOR interest-rate curve would increase (decrease) the aggregate fair value of outstanding interest-rate swap agreements by $97 million. However, any change in the interest-rate derivative gain or loss could be substantially offset by changes in actual borrowing costs associated with any future debt issuances. For a summary of the Company's outstanding interest-rate derivative positions, see *Note 7—Derivative Instruments* in the *Notes to Consolidated Financial Statements* under Part I, Item 1 of this Form 10-Q.

Table of Contents

FOREIGN-CURRENCY EXCHANGE-RATE RISK Anadarko's operating revenues are denominated in U.S. dollars, and the predominant portion of Anadarko's capital and operating expenditures are also U.S.-dollar-denominated. Exposure to foreign-currency risk generally arises in connection with project-specific contractual arrangements and other commitments. Near-term foreign-currency-denominated expenditures are primarily in euros, Brazilian reais, British pounds sterling, Mozambican meticais, and Colombian pesos. Management periodically engages in various risk-management activities to mitigate a portion of its exposure to foreign-currency exchange-rate risk.

The Company has risk related to exchange-rate changes applicable to cash held in escrow pending final determination of the Company's Brazilian tax liability for its 2008 divestiture of the Peregrino field offshore Brazil. The Brazilian tax matter is currently under consideration by the Brazilian courts. At March 31, 2015, cash of $106 million was held in escrow. A 10% increase or decrease in the foreign-currency exchange rate would not materially impact the Company's gain or loss related to foreign currency.

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

Anadarko's Chief Executive Officer and Chief Financial Officer performed an evaluation of the Company's disclosure controls and procedures as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, as amended (Exchange Act). The Company's disclosure controls and procedures are designed to ensure that information required to be disclosed by the Company in reports it files or submits under the Exchange Act is recorded, processed, summarized, and reported within the time periods specified in the rules and forms of the Securities and Exchange Commission, and to ensure that the information required to be disclosed by the Company in reports that it files under the Exchange Act is accumulated and communicated to the Company's management, including the principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure. Based on this evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that the Company's disclosure controls and procedures are effective as of March 31, 2015.

Changes in Internal Control over Financial Reporting

There were no changes in Anadarko's internal control over financial reporting during the first quarter of 2015 that materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

Table of Contents

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

GENERAL The Company is a defendant in a number of lawsuits and is involved in governmental proceedings and regulatory controls arising in the ordinary course of business, including, but not limited to, personal injury claims; property damage claims; title disputes; tax disputes; royalty claims; contract claims; contamination claims relating to oil and gas production, transportation, and processing; and environmental claims, including claims involving assets owned by acquired companies and claims involving assets previously sold to third parties and no longer a part of the Company's current operations. Anadarko is also subject to various environmental-remediation and reclamation obligations arising from federal, state, and local laws and regulations. While the ultimate outcome and impact on the Company cannot be predicted with certainty, after consideration of recorded expense and liability accruals, management believes that the resolution of pending proceedings will not have a material adverse effect on the Company's financial condition, results of operations, or cash flows.

WGR Operating, LP, a wholly owned subsidiary of the Company, is currently in negotiations with the U.S. Environmental Protection Agency with respect to alleged noncompliance with the leak detection and repair requirements of the Clean Air Act at its Granger, Wyoming facilities. Although management cannot predict the outcome of settlement discussions, it is likely a resolution of this matter will result in a fine or penalty in excess of $100,000.

See *Note 11—Contingencies* in the *Notes to Consolidated Financial Statements* under Part I, Item 1 of this Form 10-Q, which is incorporated herein by reference, for material developments with respect to matters previously reported in the Company's Annual Report on Form 10-K for the year ended December 31, 2014, and material matters that have arisen since the filing of such report.

Item 1A. Risk Factors

There have been no material changes from the risk factors included under Part I, Item 1A of the Company's 2014 Annual Report on Form 10-K.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

The following sets forth information with respect to repurchases by the Company of its shares of common stock during the first quarter of 2015.

Period	Total number of shares purchased (1)	Average price paid per share	Total number of shares purchased as part of publicly announced plans or programs	Approximate dollar value of shares that may yet be purchased under the plans or programs
January	2,325	$ 80.01	—	
February	1,024	$ 82.38	—	
March	439,722	$ 82.03	—	
First-Quarter 2015	443,071	$ 82.02	—	$ —

(1) During the first quarter of 2015, all purchased shares related to stock received by the Company for the payment of withholding taxes due on employee stock plan share issuances.

Table of Contents

Item 6. Exhibits

Exhibits designated by an asterisk (*) are filed herewith or double asterisk (**) are furnished herewith; all exhibits not so designated are incorporated herein by reference to a prior filing under File Number 1-8968 as indicated.

	Exhibit Number	Description
	3 (i)	Restated Certificate of Incorporation of Anadarko Petroleum Corporation, dated May 21, 2009, filed as Exhibit 3.3 to Form 8-K filed on May 22, 2009
	(ii)	By-Laws of Anadarko Petroleum Corporation, amended and restated as of November 6, 2014, filed as Exhibit 3.1 to Form 8-K filed on November 10, 2014
	10 (i)	Form of Commercial Paper Dealer Agreement for Commercial Paper Program, filed as Exhibit 10.1 to Form 8-K filed on January 21, 2015
*	10 (ii)	Form of Amendment to Anadarko Petroleum Corporation Key Employee Change of Control Contract (Applicable to Vice Presidents Other Than Executive Officers as of October 2013)
*	31 (i)	Rule 13a-14(a)/15d-14(a) Certification—Chief Executive Officer
*	31 (ii)	Rule 13a-14(a)/15d-14(a) Certification—Chief Financial Officer
**	32	Section 1350 Certifications
*	101 .INS	XBRL Instance Document
*	101 .SCH	XBRL Schema Document
*	101 .CAL	XBRL Calculation Linkbase Document
*	101 .DEF	XBRL Definition Linkbase Document
*	101 .LAB	XBRL Label Linkbase Document
*	101 .PRE	XBRL Presentation Linkbase Document

Table of Contents

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

ANADARKO PETROLEUM CORPORATION
(Registrant)

May 4, 2015

By: /s/ ROBERT G. GWIN
Robert G. Gwin
Executive Vice President, Finance and Chief Financial Officer

EXHIBIT 10(ii)

AMENDMENT TO
ANADARKO PETROLEUM CORPORATION
KEY EMPLOYEE CHANGE OF CONTROL CONTRACT

THIS SECOND AMENDMENT TO ANADARKO PETROLEUM CORPORATION KEY EMPLOYEE CHANGE OF CONTROL CONTRACT (this "Amendment") is made this _____ day of October, 2013 (the "Effective Date") between Anadarko Petroleum Corporation, a Delaware corporation (the "Company"), and ________________ (the "Executive"), and amends the Key Employee Change of Control Contract that was originally entered into effective as of ___________.

The Agreement is hereby amended as follows:

Appendix A, Section 5(b) is deleted in its entirety, and replaced with the following:

(b) Intentionally omitted.

Clause (iii) of Appendix A, Section 5(f) is deleted in its entirety, and replaced with the following:

(iii) if the Executive's employment is terminated by the Executive without Good Reason, the date of receipt of the Notice of Termination or any later date specified therein (which date shall be not later than 30 days after the giving of such notice), and

The heading and first sentence of Appendix A, Section 6(a) are deleted in their entirety, and replaced with the following:

Good Reason; Other than for Cause, Death or Disability. If, during the Employment Period, the Company shall terminate the Executive's employment other than for Cause, Death or Disability or the Executive shall terminate employment for Good Reason, the Company shall provide the Executive with the following compensation and benefits.

Appendix A, Section 6(a)(i)(B) is deleted in its entirety, and replaced with the following:

(B) an amount equal to the product of (1) 2.9 and (2) the sum of (x) the Executive's Annual Base Salary and (y) the Highest Annual Bonus; and

All references to the term "Restoration Account" in Appendix A, Section 6(a)(i)(C) are deleted and references to "Account" shall be substituted therefor.

Appendix A, Section 6(a)(i)(D) and Section 6(a)(i)(E) are deleted in their entirety, and replaced with the following:

(D) an amount equal to the additional Company matching contributions which would have been made on the Executive's behalf in the Company's Employee Savings Plan (the "**ESP**") (assuming continued participation on the same basis as immediately prior to the Change of Control Date), plus the additional amount of any benefit the Executive would have accrued under the SRP as a result of contribution limitations in the ESP, for the 36-month period beginning on the Date of Termination (with the Company's matching contributions being determined pursuant to the applicable provisions of the ESP and the SRP and based upon the Executive's compensation (including any amounts deferred pursuant to any deferred compensation program) in effect for the 12-month period immediately prior to the Change of Control Date); and

(E) an amount equal to the sum of the present values, as of the Date of Termination, of (1) the accrued retirement benefit payable under the Company's Retirement Restoration Plan (or, if the Executive participates in another plan that, in the sole determination of the Company, is intended to provide benefits similar to those under the Company's Retirement Restoration Plan, such other plan) (each referred to herein as the "**RRP**") and (2) the additional retirement benefits that the Executive would have accrued under the tax-qualified defined benefit plan of the Company or any Affiliate in which the Executive participates (the "**Retirement Plan**") and the RRP if the Executive had continued employment until the expiration of the three-year period following the Date of Termination (assuming that the Executive's compensation in each of the additional years is that required by Section 4(b)(i) and Section 4(b)(ii)), with the present values being computed by discounting to the Date of Termination the accrued benefit and the additional retirement benefits payable as lump sums at an assumed benefit commencement date of the later of (i) the date the Executive attains age 55 and (ii) the date three years after the Date of Termination, at the rate of interest used for valuing lump-sum payments in excess of $25,000 for participants with retirement benefits commencing immediately under the Retirement Plan, as in effect as of the Change of Control Date with such amount to be fully offset and reduced by the amount of any additional benefit provided under the Retirement Plan or the RRP in connection with the Change of Control or the Executive's termination of employment in connection with the Change of Control, including an amount that the Company determines, in its sole discretion, is intended to provide a similar or supplemental benefit (or, if the Executive does not participate in a Retirement Plan or RRP as of the date of the Executive's termination of employment, such other amount as the Company may choose, in its sole discretion, to approximate this benefit).

Appendix A, Section 6(a)(iii) is deleted in its entirety, and replaced with the following:

(iii) Until the third anniversary of the Date of Termination, the Company shall maintain in full force and effect for the Executive all life, accident, disability, medical and health care benefit plans, programs and arrangements in which the Executive was entitled to participate, at the same rates and levels (which levels may vary based on the Executive's age in accordance with the terms of the applicable plans, programs and arrangements), in which the Executive was participating immediately prior to the Change of Control Date, provided

that the Executive's continued participation is possible under the general terms and provisions of such plans, programs and arrangements; and further provided that (A) if the Executive becomes reemployed with another employer and is eligible to receive medical or other welfare benefits under another employer-provided plan, the medical and other welfare benefits described herein shall be secondary to those provided under such other plan during such applicable period of eligibility, and (B) the medical and other welfare benefits described herein shall be subject to the application of any Medicare or other coordination of benefits provisions under the applicable medical or welfare benefit plan, program or arrangement. In the event that the Executive's participation in any such plan, program or arrangement is barred due to the eligibility and participation requirements of such plan or program as then in effect, the Company shall arrange to provide benefits substantially similar to those to which the Executive was entitled to receive under such plans and programs of the Company prior to the Change of Control Date. In such event, appropriate adjustments shall be made so that the after-tax value thereof to the Executive is similar to the after-tax value of the benefit plans in which participation is barred.

Benefits provided pursuant to this Section 6(a)(iii) are contractual only and are not to be considered a continuation of coverage as provided under Code Section 4980B (*i.e.*, COBRA continuation coverage). For purposes of determining the Executive's eligibility (but not the time of commencement of coverage) for retiree benefits pursuant to such plans and programs, the Executive shall be considered to have remained employed until three years after the Date of Termination and to have retired on the last day of such period, and, if the Executive satisfies the eligibility requirements, such benefits shall commence no later than the expiration of the three-year continuation period provided in the first sentence of this Section 6(a)(iii).

The continued coverage under this Section 6(a)(iii) shall be provided at the Company's discretion in a manner that is intended to satisfy an exception to Code Section 409A, and therefore not be treated as an arrangement providing for nonqualified deferred compensation that is subject to taxation under Code Section 409A, or in a manner that otherwise complies with Code Section 409A, including without limitation (1) providing such benefits on a nontaxable basis to the Executive, (2) providing for the reimbursement of medical expenses incurred during the period of time during which the Executive would be entitled to continuation coverage under a group health plan of the Company under Code Section 4980B (*i.e.*, COBRA continuation coverage), (3) providing that such benefits constitute the reimbursement or provision of in-kind benefits payable at a specified time or pursuant to a fixed schedule as permitted under Code Section 409A and the authoritative guidance thereunder, or (4) requiring the Executive to pay the actual cost of such coverage and having the Company reimburse the Executive for such payments in excess of the rates that would otherwise be required to be paid by the Executive under the preceding provisions of this Section 6(a)(iii) (with such reimbursement, less applicable taxes, for a particular calendar year during which the Executive received such coverage to be made within 15 days following the end of such calendar year (but in no event prior to the date that is six months after the Date of Termination)).

Appendix A, Section 6(d) is deleted in its entirety, and replaced with the following:

(d) Intentionally omitted.

The following shall be added to the end of Appendix A, Section 6(f):

For all purposes of this Agreement, the Executive shall be considered to have terminated employment with the Company when the Executive incurs a "separation from service" with the Company within the meaning of Code Section 409A(a)(2)(A)(i). The Executive agrees to be bound by the Company's determination of its "specified employees" (as defined in Code Section 409A). Any payment or benefit (including any severance payment or benefit) provided under this Agreement to which Code Section 409A applies that constitutes a reimbursement of expenses incurred by the Executive or the provision of an in-kind benefit to the Executive shall be subject to the following: (i) the amount of expenses eligible for reimbursement, or in-kind benefits provided, during the Executive's taxable year may not affect the expenses eligible for reimbursement, or in-kind benefits to be provided, in any other taxable year; (ii) the reimbursement of an eligible expense shall be made on or before the last day of the Executive's taxable year following the taxable year in which the expense was incurred; and (iii) the right to reimbursement or to receive an in-kind benefit shall not be subject to liquidation or exchange by the Executive for another payment or benefit.

As expressly amended, the Agreement is hereby ratified and confirmed in all respects and shall remain in full force and effect.

IN WITNESS WHEREOF, this Amendment has been executed on behalf of the Company by its duly authorized officer and by the Executive, effective as of the Effective Date.

ANADARKO PETROLEUM CORPORATION

By: ____________________ Date: ________________

Name: ____________________

Title: ____________________

EXECUTIVE

By: ____________________ Date: ________________

Name: ____________________

EXHIBIT 31(i)

CERTIFICATIONS

I, R. A. Walker, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Anadarko Petroleum Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

May 4, 2015

/s/ R. A. WALKER

R. A. Walker
Chairman, President and Chief Executive Officer

EXHIBIT 31(ii)

CERTIFICATIONS

I, Robert G. Gwin, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Anadarko Petroleum Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

May 4, 2015

/s/ ROBERT G. GWIN

Robert G. Gwin
Executive Vice President, Finance and Chief Financial Officer

EXHIBIT 32

SECTION 1350 CERTIFICATION OF PERIODIC REPORT

Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, R. A. Walker, Chairman, President and Chief Executive Officer of Anadarko Petroleum Corporation (Company), and Robert G. Gwin, Executive Vice President, Finance and Chief Financial Officer of the Company, certify to the best of our knowledge that:

(1) the Quarterly Report on Form 10-Q of the Company for the period ended March 31, 2015, as filed with the Securities and Exchange Commission on the date hereof (Report), fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

May 4, 2015

/s/ R. A. WALKER

R. A. Walker
Chairman, President and Chief Executive Officer

May 4, 2015

/s/ ROBERT G. GWIN

Robert G. Gwin
Executive Vice President, Finance and Chief Financial Officer

This certification is made solely pursuant to 18 U.S.C. Section 1350, and not for any other purpose. A signed original of this written statement required by Section 906 will be retained by Anadarko and furnished to the Securities and Exchange Commission or its staff upon request.

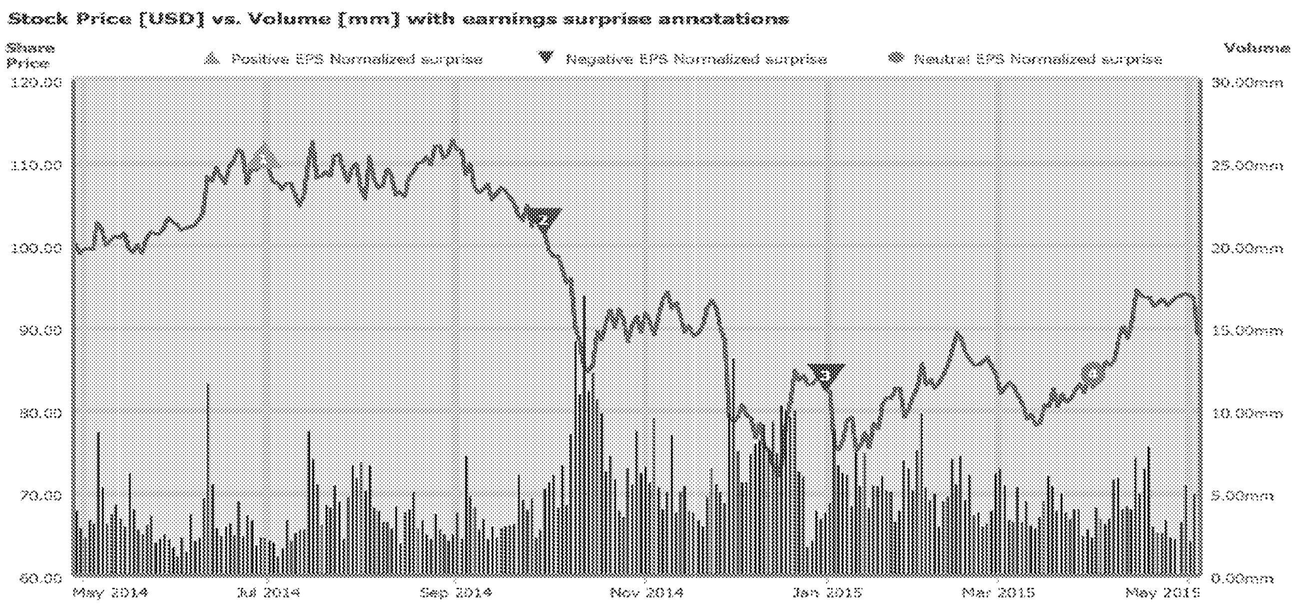
Exhibit 93

S&P Global
Market Intelligence

Anadarko Petroleum Corporation
NYSE:APC
FQ1 2015 Earnings Call Transcripts
Tuesday, May 05, 2015 1:00 PM GMT
S&P Global Market Intelligence Estimates

	-FQ1 2015-			-FQ2 2015-	-FY 2015-	-FY 2016-
	CONSENSUS	ACTUAL	SURPRISE	CONSENSUS	CONSENSUS	CONSENSUS
EPS Normalized	(0.62)	(0.72)	NM	(0.64)	(1.95)	0.48
Revenue (mm)	2500.56	2321.00	▼(7.18 %)	2623.54	10449.60	12364.89

Currency: USD
Consensus as of May-05-2015 12:52 PM GMT



- EPS NORMALIZED -

	CONSENSUS	ACTUAL	SURPRISE
FQ2 2014	1.29	1.32	▲1 2.33 %
FQ3 2014	1.26	1.16	▼2 (7.94 %)
FQ4 2014	0.81	0.37	▼3 (54.32 %)
FQ1 2015	(0.62)	(0.72)	NM

Table of Contents

Call Participants	....	3
Presentation	....	4
Question and Answer	....	6

Call Participants

EXECUTIVES

A. Scott Moore
Former Senior Vice President of Midstream & Marketing

Charles A. Meloy
Former Executive Vice President

James J. Kleckner
Former Executive Vice President of International and Deepwater Operations

John M. Colglazier
Investor Relations Professional

R. A. Walker
Chairman & CEO

Robert G. Gwin
President

Robert P. Daniels
Former Executive Vice President

ANALYSTS

Brian Arthur Singer
Goldman Sachs Group Inc., Research Division

David Martin Heikkinen
Heikkinen Energy Advisors, LLC

David Robert Tameron
Wells Fargo Securities, LLC, Research Division

David William Kistler
Simmons & Company International, Research Division

Douglas George Blyth Leggate
BofA Merrill Lynch, Research Division

Evan Calio
Morgan Stanley, Research Division

James Jan Sullivan
Alembic Global Advisors

John Powell Herrlin
Societe Generale Cross Asset Research

Paul Benedict Sankey
Wolfe Research, LLC

Paul William Grigel
Macquarie Research

Robert Alan Brackett
Sanford C. Bernstein & Co., LLC., Research Division

Subhasish Chandra
Guggenheim Securities, LLC, Research Division

Presentation

Operator

Good day, ladies and gentlemen, and welcome to Anadarko First Quarter Earnings Conference Call. My name is Sandra, and I'm your operator for today. [Operator Instructions] As a reminder, this call is being recorded for training purposes.

And now I'd like to hand the call over to John Colglazier. Please go ahead.

John M. Colglazier
Investor Relations Professional

Thank you, Sandra. Good morning, everyone, and we're very glad you joined us today for Anadarko's First Quarter 2015 Conference Call. I'd like to remind you that today's presentation contains forward-looking statements and certain non-GAAP financial measures. A number of factors could cause results to differ materially from what we discuss today. So I encourage you to read our full disclosure on forward-looking statements and the GAAP reconciliations located on our website and attached to yesterday's earnings release.

In just a moment, I'll turn the call over to Al Walker for some brief opening remarks. And we remind you that we have significantly more information and detail in our quarterly operations report available on our website. And following Al's prepared remarks, we'll open it up for questions with Al and our executive team. Al?

R. A. Walker
Chairman & CEO

Thanks, John, and good morning. I'm extremely proud of the way in which our employees have demonstrated a competitive spirit in their energy and focus on enhancing value in these challenging times. Our drilling teams continue to improve efficiencies across-the-board, highlighted by the cycle time reductions in Wattenberg, which improved about 17% over the fourth quarter of last year. And in the Eagle Ford Shale, we're drilling wells in less than 7 days. In both fields, new horizontal well performance was outstanding and the benefits we're getting from lower service costs were seeing significantly improved economics. The asset teams are also doing a great job of realizing additional volumes while moderating our base production decline. As a result, we've invested less than expected in the quarter and we've delivered sales volumes that surpassed the high end of our guidance. All told, the efficiency gains, outstanding well performance, cost savings and reduced downtime, enabled us to increase our full year sales volume guidance by $5 million BOE and to reduce our initial capital spending expectations.

We've also made significant progress in our international and deepwater activities during the quarter. We achieved first oil at Lucius and rates continue to ramp towards capacity. Also in the Gulf, Heidelberg is moving forward on schedule. The spar is ready to sail to location in the coming weeks and 2 rigs are currently drilling developmental wells. Development activity remains on schedule offshore Ghana at the TEN complex, which is more than 55% complete. Additionally, we are very excited about the recently announced Yeti oil discovery in the Gulf of Mexico and are planning appraisal activities.

Shifting to the financials. We ended the quarter by approximately -- having approximately $2.3 billion of cash on hand, which should be further bolstered by proceeds from our $700 million EOR monetization that closed subsequent to quarter end. Our cash position and access to liquidity as well as ongoing portfolio management activities have us well positioned in the current environment, as we recognized recently with 2 upgrades on our credit ratings.

We carried a significant amount of momentum into the first quarter, maximizing our operating results and continuing to safely and creatively find ways to reduce costs. I believe we're making prudent decisions in the current environment and we're taking the actions that are needed in order to put us on the right

path to preserve and enhance value today, while ensuring that we're ready to accelerate activity when the market returns for the better.

With that, we'll open it up for questions.

Question and Answer

Operator

[Operator Instructions] We have our first question for you on this one is from Dave Kistler from Simmons & Co.

David William Kistler
Simmons & Company International, Research Division

Great work on the Eagle Ford and Wattenberg, and maybe kind of diving into that a little bit. The efficiency gains looked larger than they have been in the past even on year-over-year comparisons. Is that really a result more of high grading drilling crews and completion crews, et cetera, or is that something else that's taking place under the hood? Any kind of color you could give us on that would be great.

Charles A. Meloy
Former Executive Vice President

Yes. Dave, this is Chuck. It's a great question. We're really excited about those efficiency gains. That gives us a lot of opportunity to use our capital more efficiently, as you would know. There's a lot of things that are working in our favor right now. You mentioned one of them, where there's some high-grading of crews and rigs and those type of things, as well as just a continuation of the process of improvement where we see the best performance out of each well and we make sure we use those parameters in drilling process going forward, and it's just continuous improvement. And that's -- we work on that every day and the guys in the field have just done a great job getting her done.

David William Kistler
Simmons & Company International, Research Division

Okay. Appreciate that. And if we think about that a little bit more, how should I think about that in terms of maybe secular improvement versus cyclical improvement that's taken place as a result of lower service costs and as you highlight, high grading of the crews?

Charles A. Meloy
Former Executive Vice President

Well, there's a good chance that, as we've done for years now, is we'll continue to improve these things. We're testing some additional processes that make our drilling faster and more efficient in Wattenberg as well as the Eagle Ford. So I would think that you'll continue to see these. The rate of change is always dependent upon our creativity and execution. And we're going to work really hard on those to make sure that we can do the best job we possibly can. So I foresee it continuing. I've always thought we were pushing toward the later innings, but these guys have continued to prove me wrong so I'm excited about how things are going. And I know we have some really good opportunities that are in the queue that we're going to execute on and see how they work out.

David William Kistler
Simmons & Company International, Research Division

And lastly on the thought of kind of that same continuous improvement and increasing operating efficiencies and returns. Service companies have highlighted people exploring refracs in plays where you've been drilling for a while like the Wattenberg and Eagle Ford. Can you talk a little bit about how you guys are looking at refracs at this juncture?

Charles A. Meloy
Former Executive Vice President

Yes. We've been looking at it. We have the opportunity, of course, with the well count that we have to look for those opportunities. And frankly, we're being very cautious about expanding our production profile in this market and looking for the best economic alternatives. And right now, we see that as a good forward

option in our portfolio which is just going back in there, much like we did in the vertical wells, say, in Wattenberg, where we refracked those. We see that as an opportunity. We'd like to see the technology improve and get enhanced some and make it more predictable, but we're going to hold that as a long option.

Operator

We have another question for you, and this one is from Evan Calio from Morgan Stanley.

Evan Calio
Morgan Stanley, Research Division

Staying onshore, my first question, positive production and base decline improvements in reducing line pressures in the Wattenberg LP upstream and Midstream. I mean, is that part of -- is that one-off or part of a broader plan focusing on base production that might yield more results in 2015? Any color there?

Charles A. Meloy
Former Executive Vice President

Well, Evan, I think it's not a one-off, it's a lot of great work with a bunch of folks that are really working hard to make sure we get everything we can out of our wells and that type of thing. As we've slowed down the drilling program, we've had have less SIMOPS, for instance, which has given us an opportunity to improve our run times on our base wells. And once you get these things up and running, you get the maximum production up. When you're in the transients, you don't get the maximum production. And that's how we've managed to get some of those compressor enhancements. We've also -- it has given us a chance to kind of get ahead of the drilling program and get plenty of infrastructure in place. And that's particularly true in Wattenberg and the Eagle Ford, and to a lesser extent, West Texas. So all those things kind of come together and it's a thousand really good decisions by our field guys. And they have just done a bang up job finding all the value out there, and that's what we've asked them to do.

Evan Calio
Morgan Stanley, Research Division

Just shifting gears to offshore. Several potential projects approaching FID and Mozambique, ultimately Shenandoah and Côte d'Ivoire, you mentioned in your ops report. I mean, how do you think about moving into FID and these projects in the current environment? And are you prepared to take them assuming they're matured in the FID at current interest levels versus your prior practice in monetizing and getting it carried which you can you see the benefits this quarter?

James J. Kleckner
Former Executive Vice President of International and Deepwater Operations

This is Jim. That's another good question. We've got several projects that are in various phases of appraisal or in the phases of development. Let me just pick each one and talk about that individually. So Mozambique, we're very, very pleased with the progress that we've been making on all aspects of the development. Our reserve certifications have advanced through the appraisal drilling, as we've expected. We've been successful in placing over 8 million tons in non-binding heads of agreement for LNGs uptake and sales. We've done tremendous uptake in the lending markets for project financing, and we're approaching our 60% targets for gearing. So all the things that are moving forward on Mozambique are towards advancement to FID. We're still working with the government, which is in transition but progressing very well as far as the pace of agreements that we need to finalize our plan of development and submit that later this year. If those go well, which we anticipate they will, we'll be looking at FID decision later this year into next year. So in the Gulf of Mexico, you referenced a couple of exploration appraisal projects that we've got. Let me turn it over to Bob Daniels regarding the Yeti exploration well that'll begin appraisal and some discussion about the Paon well in West Africa.

Robert P. Daniels
Former Executive Vice President

Sure. This is Bob. In Shenandoah, you mentioned, we're trying to get that -- all the information that we need to make that decision. And that's going to mean another appraisal well that's going to spud here in the second quarter. It's, typically a 120-day well. We're moving up to the Northwest of the 1,000-foot of pay that we found in Shenandoah #2. So we're looking forward to getting that information, looking for reservoir continuity, fluid, just really confirm the overall oil in place volumes that we have there so that we can then really start rolling that into development planning. You mentioned Yeti, where we had a discovery. We're going to be appraising that later this year and looking forward to that. We've already drilled down-dip sidetrack to it. And then over in Côte d'Ivoire, we have the Paon discovery. We drilled a couple wells last year, both successful. We're going to come back this year and drill another well and put pressure gauges in 2 existing wells and do an extended drillstem test to look for reservoir continuity, deliverability, those types of things that will really help start defining what that project looks like and really help advance towards that FID decision. So we've got a lot of work. And the whole focus that we have on these projects is how do we get them there as quick as possible, while making good investment decisions along the way.

Operator

We have another question for you, and this one is from Brian Singer from Goldman Sachs.

Brian Arthur Singer
Goldman Sachs Group Inc., Research Division

Seems like you have a lot of flexibility to raise or lower your completion and drilling activity levels that can drive a wide outcome of where production could end up being relative to the sequential declines coming in future quarters implied by your capital reductions and guidance. Can you talk to what milestones that you are looking for from an oil price or further cost reduction perspective to either increase completions or drilling activity and the impact that you would see on 2016 versus your long-term production objectives?

R. A. Walker
Chairman & CEO

Brian, this is Al. Let me see if I can attack your question with some good answers. First, I'm sure you have more appreciation than most that these plays are not price-specific in a generic way. Everything has got its own characteristics and own reservoir uniqueness. So there's not really a price point by which we would say, oh, we're now back into a growth mode. I think what we would say is that we need to see higher oil prices than we have today. But most importantly, they need to be higher and they need to look -- appear to us to be sustained. I think we still have some concerns that as we achieve higher prices, we could see activity increase and prices, unfortunately, could suffer as a result of higher production than people are anticipating. So we're going to be a little careful in terms of adding to that production number. If we need to, we'll continue to drill and add inventory until we're convinced that we're actually going to get good rates of return at the wellhead with that capital on the margins. So that's why we lowered our capital in part. We certainly have a lot of efficiencies that we achieved in the first quarter, but we also are not prepared and I don't feel like it's likely in the latter half of this year that we'll increase capital unless the markets for commodities do something today that we don't anticipate.

Brian Arthur Singer
Goldman Sachs Group Inc., Research Division

That's helpful. And then you've spoken on the past about the need and likelihood of industry consolidation. As a company that's been very active in portfolio management with the recovery that we've had in oil prices and valuations, wondered if you see attractive opportunities to add materially to your portfolio? And then on the flip side, how are you thinking about the synergies or comparative advantages that you see to combine other individual assets or beyond with larger companies like the majors?

R. A. Walker
Chairman & CEO

Well, certainly, in January, at your conference, I think the outlook was pretty dire for what commodity prices and oil, in particular, could look like for the balance of the year. Prices are a little higher than I

would have anticipated in January. We have an awful lot of capital sitting on the sidelines waiting to go into our industry, whether it's private equity, the public capital markets, or other forms of capital that sound like the mushroom is starting to get over $100 billion waiting to go into our industry broadly defined. So it may be a situation where we've got a lot of capital chasing a few early opportunities. So I'd say, early on, where we have opportunities to add to assets where we're active, in particular, the Wattenberg, the Delaware basin or in the Eagle Ford, we would like to add to that where we think it makes good sense. But I also would caution that comment quickly to say it's got to be a deal that really makes a lot of sense to us, because otherwise we're pretty happy with the inventory we've got and the opportunities have to look attractive on the margin relative to the way in which we would feed capital into our current portfolio. From a broader M&A perspective, I'm not sure there's a lot of takeaways from the Shell-BG deal that would be a read through for the rest of us. I think that really is a strategic call on Shell's part for wanting to be more in the LNG business. And I'm sure that will, over time, and with their hindsight that a couple of years from now will provide, it was probably a good move for them to increase something they're particularly good at. I'm not sure that's the beginning of a lot of additional consolidation in our industry, but in January, I thought we would be in this trough for a lot longer. And it looks like we're coming out of it a little sooner from a price standpoint. Although I'm still pessimistic, and I think we are as a management team, that we're going to have real robust prices for oil this year, and so you might start to see it later this year into next. Some of the development in M&A that you're making reference to, that would be my guess.

Operator

We have another question for you, and this one's from Doug Leggate and he's from Bank of America.

Douglas George Blyth Leggate
BofA Merrill Lynch, Research Division

I wonder if I could try a couple also. And may I say, Chuck, it's good to hear you on the call and congratulations, we'll miss you. Maybe I could kick off with you then, to make the most of you still being here. So the comment in the ops report about 70% improvement in the initial rates out of the Eagle Ford, is that -- was that just kind of this quarter? Or is that something you're seeing as repeatable? And if so, is it translating through to the -- I guess, is it holding up through the type curve, I guess? And I've got a couple follow-ups, please.

Charles A. Meloy
Former Executive Vice President

Yes. Doug, it's actually, I think this is something that's fairly sustainable. What we've done is, in the past, a considerable amount of experimentation with different completion designs. And looking over the fence, seeing everybody else is doing it and trying to make sure we're kind of right on the efficient frontier with our completion cost, our spacing and how the wells are performing. And I'm not saying we cracked the code or anything, but I think we have made a substantial move forward with that experimentation. And we've added some sand to our completions that I think have helped. And we learned to pump them a little different and optimize the use of the energy that we have from the frac job. So all that, I think, has just helped us make a kind of a step up in our completion value. And the first indication of that, of course, is rate. But the long haul is how the wells performed in their decline phase. And early on, these look really, really strong. So we're excited about them. We're going to use that in all our basins where it applies. And so along with the industry, I think we're all taking a step forward with regard to these completion designs and getting the most of what we put on the ground.

Douglas George Blyth Leggate
BofA Merrill Lynch, Research Division

Okay. I appreciate the answer. Maybe just a touch follow on, Chuck. What's happening to the cost of those wells with the change in design?

Charles A. Meloy
Former Executive Vice President

Well, there's several things that are going on as you're aware that -- service costs, in general, have come down substantially. We've added some product to the mix. But then, in addition to those, we've seen some fairly significant gains in the process which has allowed us to do it quicker and cheaper. And for instance, out in the Wattenberg field, we reduced our cost down to $3.4 million. And then in the Eagle Ford, they've come down as well from $5.1 million to $4.4 million. So those are all big gains for us, but it's a combination, it's the net effect of lower service costs, better processes. And then you add back in some of the additional energy and sand that we put in the well.

Douglas George Blyth Leggate
BofA Merrill Lynch, Research Division

I appreciate that. My follow-up is probably either for Al or Bob. But the balance sheet at the end of quarter now you've got Tronox out of the way, I guess, is obviously higher than it's been in terms of metrics for quite some time. But I think you've described '15 as a big year for asset monetization. So Al, I wonder if you could kind of walk us through how you see some of the major moving parts? And as best you can, given the obvious limitations, if you could offer some commentary as to whether you are exploring or testing the market on your Mozambique position and further in the pipe, there is [indiscernible] and I'll leave it there.

R. A. Walker
Chairman & CEO

Well, Doug, Bob and I will try to tackle your question. Let me address something that seems to float around from time-to-time. And as we all know, rumors are simply, oftentimes, just that. As it relates to Mozambique, we're not in discussions with anybody, we've never hired a banker around the process. Our focus is totally and completely on getting this plan of development submitted to the government later this summer, early fall. We have several things contractually we're working on to be able to get that put in place with the government. And as Jim made reference earlier, we're quite pleased with the way this new administration has been working with us. We've made significant progress to date and still have a few things to get done prior to getting that plan of development submitted. Our intent and our expectation is we will be getting other things announced here fairly soon related to the onshore development of the LNG Park. And we have every expectation that later in this decade to have our first lifting for what we believe has got to be one of the largest gas discoveries in the world in the last 3 years and it will significantly change, not only the landscape for how this country will be able to be a part of the world in the future, it'll also change, to some extent, the way in which LNG and the markets associated with it will develop. Mozambique has the ability to send LNG to both the Pacific and the Atlantic basin, so it's geographically quite advantaged. And as you know, depending upon how we kit out these wells, they're going to be $200 million to $300 million a day producers. So we have a fairly significant cost advantage over lots of other sources of LNG as this becomes very significant, so particularly during the 2020 period over that decade. So I hope that helped create a little bit of fact relative to a lot of fiction. And you're right, we do have some things that we're looking at doing with portfolio management and the balance sheet. And Bob can address those here in just a second. But any concerns or speculation or views that we're trying to monetize this particular asset are just not there. We're not in discussions and we have not hired a banker to run the process. And again, there's a lot of speculation about that, but our job today is totally focused on getting this project advanced.

Robert G. Gwin
President

Doug, it's Bob. Beyond that, we do have several assets in the portfolio that we would look to monetize this year. I think it's clear that certain of those assets just don't compete for capital relative to the other assets in the portfolio that have been driving performance are going to get the bulk of the capital moving forward. Al mentioned how much capital is chasing deals in the market today, that's created what I believe is clearly a seller's market currently. If that persists through the year, I think we should be successful in our efforts on those individual assets. That's obviously going to help the balance sheet metric you referred to earlier. That metric is higher this quarter not just because we took the Tronox -- the cash off the balance sheet to make the Tronox payment, but the write-down primarily in Greater Natural Buttes, obviously, changes that metric fairly substantially as well. That said, we're comfortable with the overall

level of debt. If you look to us on a debt-to-EBITDA basis, I think, obviously, EBITDA is down a little bit this year, but if you look over the trailing 12-months basis or on a prospective basis, we feel comfortable at the leverage level. It's easily manageable and we always have the optionality to go beyond just the traditional E&P asset sales and continue to monetize portions of our WGP holding. So lots of flexibility around how to manage the balance sheet, no significant cash cost to that debt burden with -- from an interest standpoint. And I think, frankly, the way we're doing it now with using the balance sheet and having the optionality around selling assets and monetizing WGP is far more efficient for our shareholders than, for instance, issuing equity to fund deficit spending or something, which as we made clear last quarter, isn't on the radar screen for us today.

Operator

We have another question for you, and this one comes from Paul Sankey from Wolfe Research.

Paul Benedict Sankey
Wolfe Research, LLC

I was going to ask about the reports in the press about the Mozambique process, but I think you pretty comprehensively answered that one [indiscernible].

R. A. Walker
Chairman & CEO

Paul, I'm very happy to hear you say that.

Paul Benedict Sankey
Wolfe Research, LLC

Yes. I think you addressed it. One outstanding one for me would simply be how you're viewing the future strip in your hedging program?

R. A. Walker
Chairman & CEO

Well, I'll answer that in part and let Scott Moore, who handles not our marketing but our positions that we take with derivatives. I think you've heard us say many, many times, and I'll just repeat it again, I mean, we think of hedging as just balance sheet insurance. And we try every year to think at the right times to maybe have us much half of our commodity exposure hedged just for that reason. As it relates to the current curves and what's out there, obviously, in the contango market, it's a little harder to say how we want to hedge. But with that, let me turn it over to Scott, let him talk a little bit about what we think is out there in the market and kind of how that translates into derivative activity.

A. Scott Moore
Former Senior Vice President of Midstream & Marketing

Sure. Thanks, Al. We do actively monitor the foreign markets and look at stabilizing our cash flow for balance sheet protection, as Al said. But the foreign market for natural gas, being so relatively weak due to really tremendous production growth in the fourth quarter carrying on to the first, we would like to see that market tighten up and see that will put some modest improvement in the forward pricing, which might give us more opportunities later versus the current valuations. And we're pleased to see it'll strengthen in oil markets. Still, I would say a bit cautious in terms of capital discipline in the industry and selling into any rallies. So we continue to look at this, I guess, our balancing and cost structure, and if we see things that are attractive into next year, we would carry forward with that.

R. A. Walker
Chairman & CEO

Just the only thing I'd add is keep in mind how we view hedging from a cash flow standpoint and that we're generally looking to protect longer cycle spend with longer lead times, for instance, in our exploration portfolio or our megaprojects around the world. And we feel comfortable those are funded

going forward. We feel comfortable with the current -- our current outlook for cash flow, and as we mentioned previously, our balance sheet and our asset sale capabilities to fund those things. So with that flexibility, locking in hedges at marginally better economics, it doesn't really materially change the economic profile for us. If we saw the opportunity to lock in some material cash flows and materially better economics, then maybe that would make more sense for us going forward.

Paul Benedict Sankey
Wolfe Research, LLC

Great. That to me is very clear.

Operator

We have another question for you, this one's from Subash Chandra and he's from Guggenheim.

Subhasish Chandra
Guggenheim Securities, LLC, Research Division

A couple of asset questions and one financial one. From, I think, Bob's review of the offshore projects, is it safe to say that Shenandoah and Paon are in the final stages of delineation? I suppose some of that is going to depend on these wells, but it sounds like at DST or something we're closer to the end. Second is for the onshore shale assets, how you feel about lateral targeting and optimizing that? If you feel that, that work is well developed or in its infancy, relatively? And then, finally, as I look at the E&P sector, there's a lot of focus on cash flow neutrality. I wonder though that -- what scenario you might think either Anadarko or the sector might actually have to delever over time?

R. A. Walker
Chairman & CEO

Well, Subash, what I would suggest, Bob will handle your first question, Chuck will take your second and I'll tackle the third.

Robert P. Daniels
Former Executive Vice President

All right. Subash, on the appraisal work, this is going to be the fourth well in Shenandoah. And when we go into these appraisal programs, we start working with the development teams. They put in a group to do some predevelopment work and to help define what data we need. And so where would be the best place to locate these wells, it's not just simply to focus on oil in place or something like that. So there's an awful lot of work that's gone into defining what data we still need to get to that FID decision. And the Shenandoah 4 is focused on really moving us and advancing us in that direction. I think we're planning on getting a core there in the oil column, we're going to be up dip to the 1,000 feet of pay that we had. And so that will really help with some of the modeling going forward. And it's very similar to Paon, we're drilling the #5 well this year, so we've got significant amount of lateral appraisal. And really, we're looking at deliverability and connectivity. And that gives you a lot more confidence than in what your actual development plan should be and how economic the field could be. And so we do think that with both of these wells we're going to have a real step up in our knowledge. And with the integration of the development teams doing the predevelopment work, we're going to be in a very good position to make the call as to whether we want to advance towards the FID, do an additional appraisal well, whatever it may be, based on the results of these wells, but we're moving them forward very aggressively.

Charles A. Meloy
Former Executive Vice President

Subash, this is Chuck on the -- with regard to the targeting, it's an excellent question. We put it in the mix of all the things we're trying to optimize. And what we've seen with the targeting is certain strata have faster rate of penetrations, lower frac initiation pressures, greater load recovery in IPT, so we're trying to optimize all of that to get the best economics out of these wells. So we're doing a considerable amount of work on that and deciding how to stack the laterals if we do target particular intervals. So there's a lot in this to try to push your way out on that efficient frontier, and targeting it is just one element of it.

R. A. Walker
Chairman & CEO

Subash, on your question of delevering, I'm assuming that you're talking about companies moderating to eliminating their debts to free cash flow spending. I think what you're seeing as an industry, we're still in a fairly negative free cash flow environment for most companies. That's one of the reasons, I think, you should take from the comments from this morning, we're fairly cautious because we don't quite yet see service costs synced up to the environment that we're in from a hydrocarbon price perspective. Until we start to see more of that synchronization, we're going to be pretty cautious. I think most of our industry will be fairly cautious. There probably will be some that made -- decided to take a bet and thinks that prices are going to run up and they're going to get ahead of it with their operations. We won't be one of those. As it relates to just being able to fund activity, I think Bob Gwin made a good comment a few minutes ago, that I just want to go back and reemphasize. And I think most of you know this quite well, with WGP we have additional liquidity beyond the cash as well as the lines of credit we have if we want to seek, over time, to reduce that position. And I think we've been pretty clear, our intent is not to own as much of WGP as we do today. And we see WGP giving us the ability to go into the market from time-to-time and use the cash that we see from that to put back into our operations, and in particular, things that we've seen that are good investments for us where the environment creates a good rate of return. I think, over time, it's hard to argue about the fact that we've been pretty aggressive at managing our portfolio and monetizing things and a varied rate of return syncs to the way in which we deploy capital. So as we come out of WGP, we'll continue to think about that and how we're going to put that capital to work. But from a leverage perspective, I think, industry, probably until we see service costs sync up with an environment where people can grow then grow with us, either a neutral free cash flow or a positive free cash flow, we all ought to be pretty cautious as to where we are in general. Hope that answers that question.

Subhasish Chandra
Guggenheim Securities, LLC, Research Division

No, it certainly does, all 3 of them. Just to follow-up, just curious on the Monument Prospect. If that is important to sizing up Shenandoah or is that a distinct prospect?

R. A. Walker
Chairman & CEO

I don't think we know enough about Shenandoah from a development standpoint at this juncture. We're still in the appraisal process of understanding what we've got. So we don't even have a good assessment today of what we think would be the cost to take Shenandoah to development. I think until we look at that and understand it better, any commentary from us about what we were going to do with Shenandoah would be premature.

Operator

We have another question for you, and this one is from David Tameron from Wells Fargo.

David Robert Tameron
Wells Fargo Securities, LLC, Research Division

Al, just on the service, if I think about your numbers on the quarter and some of the capital efficiency you're talking about, is there any way you can break down how much of that is service cost related? What are you seeing as far as your own operational efficiency? Is there any way to split that? And kind of what have you seen thus far? I guess what's your number as far as service cost reduction if I look at 1Q?

Charles A. Meloy
Former Executive Vice President

Yes, David, this is Chuck. I don't think I'd go into the exact figures and stuff. I think the thing you could look at to give you an idea what that split is, if you look at the drilling times in Wattenberg and the Eagle Ford that gives you a good idea what's process oriented. And then the -- associated with efficiency,

process and efficiency, and the rest of it is service cost reduction. So the combination has given us a really nice boost in this lower commodity prices to still provide some reasonable economics in our better plays. And we hope to continue to work on our processes to improve them. The reason I don't think a solid number is good right now is because it's moving on us. We continue to see additional process improvements and we continue to see some improvement in our service costs. So both are working in our favor right now and both are improving the economics even in this poor commodity market.

R. A. Walker
Chairman & CEO

David, can I just add to that real quick. I think, there'll be a day when you'll be clear as to where the costs and efficiencies are particularly coming from, but -- and we spent a little bit of time on the call this morning talking about some of the things that we're doing differently as a company in the field that are improving our efficiencies around how long it takes to drill a well or the types of completions that we're employing. And then we also work collectively and collaboratively with our service providers where we can to reduce costs. So it really is, at this juncture, still a work in progress.

David Robert Tameron
Wells Fargo Securities, LLC, Research Division

Okay. And then if I think about bigger picture, if and when, I guess, service costs come back in line what you expected, I mean, Scott alluded to the capital discipline. And obviously, there's some smaller and mid-cap players that probably have marginal acreage. But if, let's say, oil goes back to $65 tomorrow, second half of the year, do you think that the service costs or the service companies are in position to ramp and meet the industry activity levels? Just given how deep they've cut, if everybody decides fourth quarter, hey, let's start ramping for '16, is there going to be a lag period? And do we risk the potential for service cost inflation headed into '16?

R. A. Walker
Chairman & CEO

For those companies that might choose to be more active the second half of the year because they believe that prices are going to be higher than they are today and believe they can continue to achieve service cost reductions so that they get a good rate of return, I'm assuming they're thinking about how they run their business in a way where rate of return means a lot to them. The service companies themselves have not really, to date, shown an ability to deliver services not only in a timely manner, but in a very quality manner. In fact, we're seeing tremendous support from the service sector. I'm not currently concerned about it, but our activity level as an industry is substantially less as you well know than it was even 6 months ago, and substantially less more so than a year ago. The service industry, I think, like the upstream business, has the ability where the economics support it to do the right thing and provide the right service at the right cost. I think from our perspective, we just need to continue to monitor that synchronization of service costs and hydrocarbon prices in a way where we think, on a sustained basis, we can get a good rate of return.

Operator

We have another question for you, and this one is from James Sullivan from Alembic Global Advisors.

James Jan Sullivan
Alembic Global Advisors

Just wanted to go back to Côte d'Ivoire for 1 second, there've been a couple questions on it. But I just wanted to ask, so you guys post the DST, are there other hurdles to a go-forward decision for FID besides the underground stuff? Is there -- how's the work, the situation with the government? Or are there any other limiting factors that would -- that you guys have to get over to get to sanctioning the project?

R. A. Walker
Chairman & CEO

No. I think, at this point, it's really technical and commercial internally. Our relationship with the government of Côte d'Ivoire has been excellent. The government has been very responsive. In fact, we went in and asked for a 2-year extension to give us more time to get the appraisal work done so that we could put -- submit a very good plan of development, should we end up with that outcome. And they were amenable to that. They really would like to see another development. They have internal needs for the cash and also for any hydrocarbons that may come into shore. They're very, very supportive of everything we've been trying to accomplish out there. They have an existing oil and gas industry there with production and a ministry and oil company in Petroci that understands the needs of the operators and is very flexible about helping the operators be successful and therefore, Côte d'Ivoire be successful. So from an onshore side, we're in a very good situation.

James Jan Sullivan
Alembic Global Advisors

Okay, great. That's really helpful. Just to switch then over into the onshore arena. You guys had a couple of announcements about Permian midstream pieces, I think, pipeline and gas processing. Can you guys just comment on what you think remains necessary on the systems and infrastructure and midstream side before the Permian is ready to kick into high gear? And I would, obviously, you can take the question as commodity-agnostic. I know we're looking at the likelihood of some volatility and you guys really emphasized that you want to be cautious looking ahead. But just on the systems side, taking no account of the oil price, how far are you along there on a capacity side to being ready to rig up there?

R. A. Walker
Chairman & CEO

Yes, Jim, good question. We're very excited about our Permian assets. It's -- the Wolfcamp in particular as it's shown tremendous upside for us. So much like we did in Wattenberg, we made some strategic moves to capture what we viewed as critical infrastructure in the Permian Basin, the Delaware portion of the Permian Basin. And they included the Nuevo plan as you're -- I think you're alluding to, as well as the -- what we call the DB JV, which is some pipeline assets. So we put together a really nice grid. If you go into our operating report, you can see that grid. And would that grid does is allow us to develop our substantial acreage position out there very efficiently and effectively without long runs on incremental pipes. The combination of those 2 pieces of infrastructure along with our position in the [indiscernible] plant that starting up here. Now has given us very nice, very efficient, quick response type of position within the basin. And so we really are waiting on commodity prices. At the end of the day, we're in a really good position with infrastructure. It still has a lot of work to do to upgrade it, to continue the expansion that would keep up with the drilling program, but it's given us a great footprint. If you look back at the Wattenberg story, you'll see a very similar move and very effective move for us. So I think we're in a good spot. We have a lot of opportunity for upside to capture the full value chain out there, and that's what we set out to do and I'm very proud of what we've accomplished.

R. A. Walker
Chairman & CEO

Yes. This is Al, let me add to the fact, I think, Chuck has done an incredible job of synchronizing our midstream and upstream business. Our ability to add value over things that we control in the midstream space is incredible. I mean, you look at what we do in Wattenberg and boy, it's just a blueprint for how you do it right. That was under the direction of Chuck and a lot of good people that work with him every day. But at the same time, I think few companies understand the need as well as have the ability to execute the way in which they combine their midstream and their upstream and understand you need to control both. And I think that's one of the reasons you see such good success from our standpoint from the Wattenberg field versus other operators in the field. And we hope to do that again in the Delaware and certainly feel like we've done a pretty good job of that as well in the Eagle Ford with the way in which we've handled our midstream there as well.

Operator

We have another question for you, and this one comes from, David Heikkinen from Heikkinen Energy Advisers.

David Martin Heikkinen
Heikkinen Energy Advisors, LLC

As I look back at the first quarter, you guys are much closer to cash flow and CapEx balance than many of your peers. And Al, you've been pretty clear on your outlook and your outspend for the rest of the year. As you think about positioning at the year end, can you talk about how you build a backlog of drilled uncompleted wells in Wattenberg and Eagle Ford? How that brings you closer to cash flow balance? But maybe more importantly, how it can impact your outlook for activity levels and growth and the commodity price recovery?

R. A. Walker
Chairman & CEO

Well, you can expect, given the way in which we're allocating capitals here, David, you're going to see dry gas continue to decline sequentially each quarter. We anticipate the exit rate for this year for oil to be relatively flat year-over-year. So if you think about that from a rate standpoint and you think about what we have in inventory, when we see prices really give us the right rate of return at the wellhead, we're prepared to go back into a mode we've been in historically. I think we are taking a very cautious view and trying to do what we believe is the right thing in an environment where creating and adding value is more important than growth. And I'm not worried that when the day comes and we want to have growth that we can hit that accelerator again. I'm pretty proud of the fact that when we look at our exit rates for oil production, we're going to be pretty flat year-over-year and the decline is largely going to come from just dry gas which, as you well know, it really doesn't have a lot of economics today. And hopefully, natural gas prices in the U.S. will improve through the balance of the decade, as some of this goes out of our country through LNG and that commercial and industrial demand picks up. But I think that's kind of where we are today. And I'm not worried about getting back into a growth mode when we see higher prices that look sustainable and that will give us a good rate of return over the production profile of the field or the asset.

David Martin Heikkinen
Heikkinen Energy Advisors, LLC

And I guess that is the point of the drilled uncompleted backlog. What is the rate of return or have you ever thought on the inventory around that drilled uncompleted backlog in the Wattenberg?

Robert G. Gwin
President

In terms of what's an optimal amount or what are expected amount is?

David Martin Heikkinen
Heikkinen Energy Advisors, LLC

Where do you think you will be? Yes, exactly the expected amount.

Robert G. Gwin
President

Well, I think back in March, if you recall, we thought we would end the year at about 125 wells. That may increase another 25, thereabout, if we don't see the type of sustained higher price environment Al's making reference to. So a modest build from where we were in March, but not a lot.

Operator

We have another question for you, and this one is from Bob Brackett from Bernstein Research.

Robert Alan Brackett
Sanford C. Bernstein & Co., LLC., Research Division

A quick couple. One, on the Powder River farm out, is that farm out the entire strat column? Or is it limited to certain zones?

Charles A. Meloy
Former Executive Vice President

It is limited to certain zones, Bob.

Robert Alan Brackett
Sanford C. Bernstein & Co., LLC., Research Division

Which are those?

Charles A. Meloy
Former Executive Vice President

It's those below the coalbed methane.

Robert Alan Brackett
Sanford C. Bernstein & Co., LLC., Research Division

Got you. And for Yeti, the area under closure looks comparable to Big Foot or Cascade. Is that a reach or should we assume comparable oil in place?

R. A. Walker
Chairman & CEO

Bob, I said, at this point we don't know, that's why we have to drill the appraisal wells. With the 1 point and the area that we have, you could get the visual. But I think you have to get more on the sand distribution and continuity across that overall structure. So we're going to be appraising it later.

Operator

We have another question for you, and this one is from Paul Grigel from Macquarie.

Paul William Grigel
Macquarie Research

With the operational improvements you've outlined, has there been a change to your view on what the base decline is for the company? And then subsequently, what you view as a maintenance CapEx to hold production flat going forward?

R. A. Walker
Chairman & CEO

Okay. Both of those are pretty understandable questions, and appreciate you asking them. I think back in March, we told you we thought we had about $3 billion spend to be able to maintain capital or to have a maintenance CapEx number. That number is now down to $2.7 billion to maybe to $2.9 billion. So we've lowered that threshold in this process. And some of that has to do with the fact that we've done a great job to date reducing the base decline. Our guys and gals that handle that part of our assets have just done a phenomenal job. I'm sure there's going to be continued improvement as we begin to focus on it in the last quarter. As we moved away from growth, we found a lot of things that had been very positive. And I think that you should continue to expect we'll find ways to reduce the type of decline we've had in our base historically. And that's probably one of the real benefits -- if there's a benefit of $50, $60 oil, it's focusing on trying to do what you do every day, less expensively and better and improve your efficiency. And our ability to improve our efficiency around our base decline is probably one of the real super positives that came out of the first quarter.

Paul William Grigel
Macquarie Research

Great. And then just taking a look at the CapEx outlook, obviously, lowering the high end. Given the increased drilling efficiency and the additional service cost reductions you guys have outlined that you received in March post when the guidance was set, could you discuss the thoughts on only moderately reducing the CapEx guidance and how much flexibility is built into that outlook?

R. A. Walker
Chairman & CEO

There's quite a bit of flexibility in that outlook. We watch that fairly closely. If we oil prices further back up through the course of the second half of the year, we'll drill and put more than the approximately 25 that I made reference to earlier, that we expect to add to the drilled but not completed category. We have no interest in adding to an oversupplied market with production that doesn't give us a good rate of return.

Operator

We have another question for you, and this one comes from John Herrlin from Societe Generale.

John Powell Herrlin
Societe Generale Cross Asset Research

Just a quick one for Chuck since you are leaving us. You've been through a lot of cycles, Oryx, Kerr-McGee, Anadarko, deepwater shales, conventional. When you look at the different play types the industry has pursued, from a planning perspective, is it more difficult to manage something that's as iterative with the shales or deepwater given relative infrastructure type risk? I mean, how do you view how the business has changed over time in your career?

Charles A. Meloy
Former Executive Vice President

John, great question. It's been a great ride through all of that. And there are different challenges in each one of them. The thing that we've found is as we study on these and prepare to execute these programs, if we get the right folks on it and the right service support, we've been successful. And we've worked really hard as a company to get the right vendors tied in to us and the right folks onboard within the company, make sure we had right talent attacking these problems. And as long as we go at it right, as long as we attack it right and as long as we have the support from the vendors community that we've always enjoyed, and there's so many great ones out there that each of them have their individual challenges, but each of them you can accomplish if you go at it right.

John Powell Herrlin
Societe Generale Cross Asset Research

Last one for me is Thorvald. When will that TD?

Robert P. Daniels
Former Executive Vice President

Yes. John, Thorvald is probably got a couple of months, 2 months maybe. We're about halfway down. It's a 30,000-foot well, so we've got a ways to go.

Operator

I have no more questions for you.

R. A. Walker
Chairman & CEO

Well, operator, thank you. I'd like to close with a couple of things. One, I really like to take a moment and thank Chuck and Cathy Douglas, who are both here this morning, who we announced last week were going to retire. Both had incredible impacts on our company, socially, culturally and operationally. To use a sports analogy, we are not going to replace them, we're going to reload. You cannot replace Cathy and you cannot replace Chuck. I'm pretty confident we can reload and do things the way we've been doing it

because we have a tremendous culture, we have a great organization, but we're going to truly miss both of them. So from all of us, it will be very difficult to be on these calls in the future and not have both of them around the table.

And the last thing I want to just continue to emphasize is that we are in this environment really seeking value. We're going to continue to look for value, we're not going to look for growth, and we're going to maintain flexibility so that when the markets do give us that right opportunity to go back into a growth mode, we're ready. But I think this will be one of the last companies you see trying to grow in a market where there's as much uncertainty we believe there is in terms of the expected rates of return that would come from a price environment today that was a little choppy.

So I know you guys have a busy day. Appreciate everyone dialing in this morning, loved the questions, and we'll talk to you in a quarter. Thanks so much. Bye-bye.

Operator
Thank you. Ladies and gentlemen, that concludes her conference call for today. You may now disconnect, thank you for joining and enjoy the rest of the day.

Exhibit 94

S&P Global
Market Intelligence

Anadarko Petroleum Corporation

NYSE:APC

Company Conference Presentation

Wednesday, May 20, 2015 1:30 PM GMT

Table of Contents

Call Participants 3

Presentation 4

Question and Answer 10

Call Participants

EXECUTIVES

Robert G. Gwin
President

ANALYSTS

William A. Anthony Featherston
UBS Investment Bank, Research Division

Presentation

William A. Anthony Featherston
UBS Investment Bank, Research Division

Okay, we're going to get started with our first presentation today, which is Anadarko Petroleum. Anadarko's been one of our top picks in the E&P sector for the last year. So we think it offers one of the best combinations of growth, strong balance sheet, capital flexibility in a challenging market. And it's the largest -- trading at the largest discount to NAV within our large-cap universe. So here to tell us about it is Bob Gwin, who's Executive VP and CFO. Bob?

Robert G. Gwin
President

Bill, thanks. Thanks for having us again here in Austin. Great location for a conference, one we always look forward to coming to. Thanks, everybody, for getting up early this morning to listen to us. It's always fun to kick things off. Our cautionary statement on forward-looking things that I might say today, results may vary.

So many of you are familiar with the Anadarko story. Just to hit a couple of highlights here. We've had a pretty good track record over the course of the last several years. We'll cover that on the next slide. We've got a deep portfolio. It's balanced, internationally and domestically, gas and oil, conventional and unconventional. We focus a lot of time and effort on capital allocation across those various assets to meet the objectives that we set out. Usually, that's focused on delivering cash flow, reserve and production growth per debt-adjusted share. In the current environment, we've changed that around a little bit, as I'll be talking about this morning.

We've got a number of competitive advantages that have served us well and we try to continue to capitalize upon. And we have probably been one of the most active portfolio managers in cycling the portfolio, being willing to sell assets or portions of assets and redeploy the capital into higher-value opportunities across the portfolio.

The map and the barrel will give you a little bit of an insight into how we -- how the portfolio is split across the world. Primarily, we're focused on North America, with distinct oily opportunities in Africa as well as a world-class emerging LNG project in Mozambique that I'll also mention some stuff about this morning.

The track record I referred to earlier, and it's one that we're proud of. This is solely attributable to excellence in our operations. Our operating teams and our field folks have done an absolutely tremendous job of delivering upon the potential of the portfolio that we've put together several years ago.

We set out a goal of 5% to 7% compounded annual growth in production. They delivered 8%. Not only did they do that, but they did it with tremendous free cash flow generation, averaging almost $1 billion a year over the 5-year period, consistently replacing more than 150% of production, which we think is impressive for a company of our size. We do it at competitive costs. And our exploration team has delivered exceptional performance, and we'll touch a little bit on the tremendous value that they've added to the company over time.

And as I mentioned, we're going to be active in portfolio monetizations. And we've done it to the tune over that 5-year period of almost $13 billion, which has given us a lot of leverage within the portfolio to continue to grow without accessing the capital markets.

So these are our current expectations. This slide differs from the initial guidance that we laid out back in early March on our investor call. This is the information that we put forward with our first quarter results. The production -- the good news here is the production number's up and the capital and the cost structure is down. That's always a good combination. The production numbers here are 5 million barrels higher than they were at the beginning of the year. So we're looking at a little over 300 million barrels for the year.

And the capital, we brought down the high end of the range here. And our capital spend in the range is a little wider than we might usually look at, at this time of the year, but it's because we got a lot of flexibility of where we go deploy capital during the second half of the year, depending upon the environment we find ourselves in. And I'll mention where some of those levers are as I go through the talk this morning.

If you look -- I want to point you to that chart at the top right. You can really see what we've started to do with this year's capital allocation versus the traditional way that we've looked at capital. I don't know if you can see the -- if it's too small or not, but the green wedge here is our short cycle growth capital. We've essentially removed that from the 2015 plan and looked at not trying to drive growth, but trying to maintain flexibility and to allocate our capital into the maintenance side, replacing production and into shorter -- I'm sorry, into medium and longer-term growth opportunities. So if you think about the maintenance capital component of this, that's basically what's in the short-cycle box down here at the bottom, which is roughly half of our capital expenditure allocations for the year. We think the maintenance capital number now to maintain a production level consistent with 2014 is somewhere in the neighborhood of $2.7 billion, and that's down from closer to $3 billion when we talked to you at the beginning of March. That's a result of our ops folks doing a great job of driving down service cost, primarily onshore in the U.S., and becoming even more capital-efficient than that part of the portfolio always was.

We're going to continue to invest in the medium and the long cycle, though. We think that those offer better return characteristics, as we would hope to see some oil price recovery further in the future. Mid-cycle, a big chunk of that is -- part of it is what we're doing in our megaprojects, and a big chunk of it is in the Wolfcamp that I'll talk about.

And then in the longer cycle, we're going to continue to invest in exploration because of our success there and our ability to turn it into a profit center in and of itself.

So I'll talk first about the U.S. onshore. The chart at the bottom shows you the success that our teams have had driving forward a number of very impressive plays over the course of the last several years. The growth potential in these plays is evident. As you can see in the 2015 numbers, however, we're not focused as much on growth here. We are still growing oil volumes. Oil volumes will grow about 7% this year, we think, as a rough number, even though our overall volumes will be relatively flat. Our exit rates for oil, we think, will be about equivalent in 2015 to the 2014 number. Capital-efficient, I mentioned earlier, we're adding volumes, these wedge volumes at only about $35,000 per flowing barrel, $13 of BOE development cost, very impressive statistics, we think. But the absolute returns here, even though in a couple of fields they're very strong, the dollar profitability is simply not what it was in the U.S. even with the service costs coming down. And so we're going to be cautious as we see prices maybe begin to inch up here. We're going to be cautious about investing additional capital until we see returns as attractive as we expect they should be in the U.S. in the future.

One of the things we've put on this slide is leveraging our Midstream advantage. We did that exceptionally well in the Wattenberg. And when I talk about the Eagle Ford in a minute, I want to talk to you about what we're doing there to build that foundation for growth.

Wattenberg is a very impressive asset. It's more than a 1.5 billion barrel field. You can see the growth at the bottom, how the horizontal growth has taken off, replacing what is, I think, somewhere in the order of magnitude of 60-year-old conventional vertical field here. The team has done a tremendous job of driving down costs, improving efficiency. Well costs here are now less than $3.5 million per well. EURs continue to improve as we continue to fine-tune our spacing and our completion methodology. This is an asset that has been great and continues to get better. Returns, even in this environment, are now north of 45%, which we think is probably one of the better-returning assets in North America today. And that's -- a significant amount of that is driven by the fact that we have a tremendous position in the minerals in this area. About 40% of our operations in the Wattenberg are on fee-mineral acres that we own. And accordingly, the economics are enhanced by the fact that we either -- look at it like we don't pay a royalty or we pay it to ourselves. There's a little chart here down at the bottom right that attempts to show you some of the relative economics. The nice thing about this is in a lower-price environment, the relative value of owning the minerals here is even greater.

And so our downside has been protected and the returns have been enhanced by owning the minerals, and it creates what is a very good asset without those minerals that turns it into an absolute phenomenal asset with the minerals. We control a significant amount of our infrastructure in the area by being able -- through our Western Gas Partners MLP. By leveraging Western Gas Partners' position, we've been able to capitalize upon its spending on capital. And West owns a piece of this value chain in transportation and frac trains down at Mont Belvieu. So we really have a pretty nicely vertically integrated asset here really from the wellhead to the frac train. And so it's an area that we continue to focus on as our primary place where we're going to invest capital in North America. We're running about 8 rigs here in 2015.

The Eagle Ford. We're going to run about 5 rigs here down from 10, I believe, it was last year. Yes, it says on the slide, it must be true. Our drilling cycle times here also continue to get better, drilling longer laterals for less money. We're seeing very strong well performance in the area. The teams, again, here have really done a great job of focusing on the base, focusing on efficiencies and capitalizing upon the scale we have in the field.

If you -- you can see the volume growth that we've been able to deliver up to this point, we're still going to grow this asset more in 2015 despite the fact we're bringing the rigs down. But this is very much another story about driving efficiencies to improve economics, driving down cost to improve economics, and we're getting better than 30% rates of return in this field in the current cost and price environment. So certainly, not nearly as strong as we've seen in the past, but acceptable rates of return, which is why we're continuing to invest in this area.

The Delaware is probably -- I think probably the most exciting opportunity that we've seen for a while, certainly since the Wattenberg. This is big and it keeps getting bigger, the economics keep getting better. I hope most of you are familiar with our position here. But if you're not, we have over 600,000 gross acres, over 250,000 net acres. This is a 50-mile range from the northwest of this map to the southeast of this map. It's an absolutely huge geographic area. You can see that as you move from the west to the east, we see EURs decreasing, but oil recovery is increasing. We are spending a lot of time here teeing this thing up for the future. We get asked a lot about economics here, and the economics here aren't stellar yet. And the reason is we're not moving into a pad drilling or a manufacturing mode here. We're doing science. We're drilling wells on a one-off basis across our acreage, trying to understand the geology better. We think there are multiple commercial zones here, and we're spending a lot of time and a lot of money building out infrastructure. A lot of that money that's being spent is Anadarko's Midstream spending. A lot of it is our Western Gas subsidiary's Midstream spending. We're following a model here that we followed in the Wattenberg, that if we -- that rather than drilling wells and waiting on pipe, it's -- the appropriate way to do this is to build out the infrastructure, make sure -- treat it like a megaproject, where we're building infrastructure, we're continuing to invest in capital, making sure that we have ample deliverability, ample power, ample water handling, and be in a position then, when we move into a manufacturing mode, to move quickly and to shorten the time between when we spend capital and when product is sold, which obviously has a significant positive impact on returns and on our cash flow generating capability.

As we do that, obviously, the science that we're doing is making the per-well economics much better, and the chart at the bottom left is meant to display that. Just what we've seen in the work that we've done in the early stages, we've already seen a 30% increase in our EURs. And obviously, that has a materially positive impact on the promise for the future and the economics for the future. Lots of locations, over 5,000 locations here. We still -- I didn't mention on the earlier slides, but over 4,000 locations in the Wattenberg, over 2,000 locations in the Eagle Ford, lots of running room in these 3 encore -- onshore U.S. plays. And give us, I guess, comfort in saying that when we're ready to ramp back up our rig count, we've got lots of running room to be able to deliver very profitable returns in the future onshore in the U.S.

I want to move to offshore a little bit and look at the megaproject portfolio. One of the things that I think is unique about our portfolio relative to many of the U.S. onshore peers is that we also have a material deepwater component to our business. It is poised to deliver a substantial amount of free cash flow going forward. The chart at the bottom shows you a little bit of how we've been essentially spending on new projects, the cash flow that is being generated by the existing projects. Those projects are listed in the charts at the top right here. And you can see we've brought them on fairly consistently about 1 or 2 a year for the last several years. That remains true. If you were to try to draw a line up from 2016 in that

chart, you'll see Heidelberg and TEN both coming on in 2016, and then Mozambique trains start to come in behind that towards the end decade. What that results in is a substantial amount of free cash flow generating capability that we can take here and redeploy other places in the portfolio. It gives us a lot of flexibility around capital allocation going forward.

One of the things that we've done historically is that we've sold pieces of these developments to fund the capital associated with them. And it's added a tremendous amount of leverage within the portfolio without adding balance-sheet leverage. It's also significantly enhanced the rates of returns associated with each of these projects. So that by the time we brought, for instance, Lucius on, we had essentially had our development capital carried. And when we've put Lucius in place and entered into production-handling agreements with other fields in the area, the economics at the spar become very, very attractive. So there are a lot of different ways that you can take these deepwater assets and make them more profitable than the intrinsic rates of return might otherwise indicate.

I'll touch on the Gulf of Mexico for a second. I mentioned Lucius. It's a very attractive project that we have now ramped up to nameplate capacity of 80,000 barrels per day. Obviously, we're very pleased with that. Its twin, Heidelberg, is moving on time and on budget, scheduled to come online in 2016 and give us that next leg of growth in the Gulf of Mexico. Shenandoah, as mentioned here in the middle, not a lot to add on Shenandoah today, other than to mention we are drilling an appraisal well there, and we continue to move that project towards development in the future.

We have a high working interest across our portfolio. We've got 7 facilities out here. By having that kind of breadth of facilities, by having good project development expertise and a strong exploration capability, the Gulf of Mexico becomes a place where our core skills create a competitive advantage, where we've been able to drive very profitable and increasing the oilier operations here over time.

Speaking of high-margin oil, we're getting a lot of it out of Africa these days. We brought on El Merk that many of you are familiar with in Algeria. Jubilee is producing at a very high rate. Offshore Ghana, I mentioned we're bringing on the TEN development in 2016. So coming out of Ghana and coming out of Algeria are very low operating costs, very high-margin oil projects. Even in the current oil price environment, these are very attractive, generate a lot of free cash flow and give us cash that we can redeploy elsewhere in the portfolio. And Algeria has been a legacy asset of Anadarko's for, I don't know, 25-plus years. And Ghana is certainly emerging as that as we bring TEN on in 2016.

Mozambique many of you are familiar with. We had a very exciting announcement on Monday morning that we have named our engineering procurement and construction contractor group following an extensive competitive FEED process. One of the data points that was in that release that you may or may not have noticed is that the size of Mozambique, the size of the production opportunity from the first 2 trains went up. We originally were looking at 2 5 million tonne-per-annum trains in Mozambique, and we've worked with the engineering firms to now be looking at 2 6 million tonne-per-annum trains at the same cost that we were expecting for the 5 million tonne-per-annum trains. So a combination of the current service cost environment and the good work of the FEED contractor has put us in a position where we've got a 20% uplift in potential volumes at the same economics. And obviously, that's pretty exciting when you start to look at the return potential and the size potential of just the initial 2 trains in Mozambique. And as many of you have followed, the amount of gas here in the plan, the forward plan is for several trains coming in behind that.

Also, by entering into this, it moves us closer into the submittal of a plan of development to the government and it moves us closer to being able to reach FID. And our goal here is still to be able to deliver first cargoes around the end of the decade. The economics here are very impressive. We've got, as I said, 12 million trains -- 12 million tonnes per annum for the first 2 trains. We've contracted through HOAs with offtake providers for about 2/3 of that, 8 million tonnes per annum. We've got LOIs for approximately 60% of the capital cost here in the form of project financing. Our goal has always been to be somewhere in that 2/3 range. Really, each piece of this project continues to move forward, and we continue to advance it. And it's a very -- first cash flows and first cargoes are still a ways off, but it's increasingly being derisked, and the value of the opportunity is becoming greater and greater to Anadarko and its shareholders as we move forward.

Touch briefly on exploration activity. You can -- I won't read the map to you here, but you can see about half of the activity around the 9 to 12 wells that we're planning, and this is always flexible based upon discoveries and what we might want to do around appraisals. But about half of that's in the Gulf of Mexico. Speaking of discoveries and appraisals, we had the Yeti discovery that we announced already earlier this year. We'll move toward an appraisal well at Yeti. We're appraising Shenandoah. If you look at Côte d'Ivoire, we'll be doing an appraisal and a drill-stem test at Paon. The goal there is to move Paon towards development and start to push that now in a direction of being able to define a timeline to deliver first oil offshore Paon and the first deepwater oil out of Côte d'Ivoire, which is a nice complement to our Ghana position. Colombia is also an exciting place in 2015 for our exploration team. We've got 2 wildcat opportunities that we'll be drilling offshore Colombia and a very significant seismic shoot over our 16 million acre -- a portion of our 16 million acre position in offshore Ghana. Lots of prospects, lots play types. This is one of the more exciting things that our exploration team is working on currently. And as we move forward, we've -- for the last couple of years, we announced our exploration results each of our quarterly calls, and we look forward to updating everyone in the future at what we're finding. But certainly, a great start to the year with the Yeti discovery, which gives us another development opportunity in the Gulf of Mexico. We're also doing a significant seismic shoot in New Zealand to determine prospectivity of a substantial acreage position there as well.

The coolest slide, I think, in the presentation might be this one. People think about exploration when think about how we're spending capital. And why are we spending capital, outspending cash flow to spend capital on things like these mid-cycle opportunities and long-cycle opportunities? If you think of the long-cycle as exploration, why would you spend money in a low-cash-flow environment? Why would you spend money on something that's long cycle? Well, this is why. Exploration has become a very significant profit center in and of itself. Their track record is unmatched when you look at what they've done with the drillbit. But when you look at what they've been able to do for the company financially, I think it's truly unmatched. We spent about $10 billion since 2005. Now what's that $10 billion gotten us? Well, they found about 6.5 billion barrels of resources, which is exceptionally impressive. But we've been able to sell either through farming out prior to drilling some of these opportunities or selling down discoveries, which would include for instance the selldown that we've done in Mozambique to derisk that project. We've been able to bring in $13 billion of cash associated with these -- with the $10 billion spend. So if you spend $10 billion, you bring in $13 billion. And we're left with 5 billion barrels of those resources that we've retained as well as current production of 250,000 barrels a day that is a part of those discoveries. So we've been able to use dollars to generate even more dollars, create optionality, keep assets that help us to drive future growth. And we think this model is not only sustainable, but it's ongoing today. Down to the bottom right, you see that we've raised a couple of hundred million dollars through farm-outs. So by the time we're drilling some of the opportunities I've mentioned to you earlier, we're drilling it. We're derisking it. We're not exposing as many of Anadarko's dollars to these opportunities. We're getting more bites at the apple for the same amount of capital. And we think this is something we'll be able to extend well in the future because the value is in the people and what they've been able to deliver.

An obligatory financial-position slide since I'm the CFO. We have plenty of liquidity, a nice cash position, $5 billion of credit capacity in the form of our revolvers and our commercial paper program. We've got a lot of flexibility about moving capital expenditures up or down to meet either our cash inflows or our liquidity position.

We announced in early March that we would expect to outspend cash flow this year because of that intermediate and long-cycle spend. And I think we'll continue to do that, but we also came out back in early March telling you where we're going to pay for it, announcing the sale of our EOR assets. We've now closed $700 million sale of the assets in Wyoming. So essentially, putting no pressure on the balance sheet in 2015 through outspending cash flow. And as we look at 2016, we'll try to decide if we want to still go down that path or if we want to spend within cash flow or if we want to start to ramp up some of the short-cycle cash opportunities if the return environment is more attractive than we find it today.

We also have a significant ownership position in some other assets. We'll be marketing some other E&P assets during the course of the year, things that otherwise probably wouldn't be funded in our portfolio, but still have economics that are attractive relative to the opportunities of other companies or private equity-backed teams out there. And we have a substantial ownership position in our publicly traded MLPs,

around $12 billion of value in our Western Gas Equity Partners MLP, ticker symbol is WGP. We've sold some of that into the market over time. I've made statements in the past that we expect to continue to monetize that over time. While we own it, it's earning about a 2% yield, which is 6x what you can earn on your cash today. So we're in no hurry to sell these -- the position, but it's something that gives us flexibility around how to fund things without accessing the capital markets with Anadarko securities.

And since I mentioned earlier that our goal here is to grow on a debt-adjusted share basis, obviously focusing on not expanding that denominator, but rather contracting it over time materially helps us achieve that objective.

We've come to the -- everybody's favorite slide, the last slide. Just to retouch, we think the portfolio is unmatched from a depth and quality standpoint. We think the balance is appropriate and -- rather than betting on one commodity or the other. We think we're quite good at allocating capital and have flexibility to change that as the year goes on, either deferring more completions or completing more wells. That's the easiest valve to turn in the short term. There's some things we might also want to do in the medium- and long-cycle bucket. Opportunity is abound in the portfolio, so it's really a question of what's the future environment look like. And how do we want to seize upon that either in the current environment or maybe wait and do it going forward?

Active portfolio management, whether that's buying assets periodically or continuing our traditional view of selling things that otherwise might not get funded within the portfolio. And really, what the overall focus is -- last bullet point. Our goal here is to create long-term value. It's not to deliver quarter-to-quarter growth that might get somebody's attention, it's to grow as fast as we can for as long as we can in the right environment, where we can do so profitably and to be fiscally conservative and responsible in an area -- in an era of volatility, like we're in today, until we see some clear signs that the results of our efforts and the results of your dollars that we're investing are going to generate the right kinds of returns to deliver the best long-term value for the shareholder.

So Bill, I think, yes, that is our last slide. Yes, we've got -- well, I wanted to leave 1 minute, but there's 5, I guess.

William A. Anthony Featherston
UBS Investment Bank, Research Division
Yes. So do we have any questions for Bob or Anadarko?

Question and Answer

William A. Anthony Featherston
UBS Investment Bank, Research Division

Maybe I'll start off with a quick one. Can you comment a little bit on what you're seeing in the M&A market? I mean, you've been very active in terms of portfolio management, but you would think where the strip is that it might not be an ideal time to sell assets. But on the other hand, there's been a tremendous amount of capital raised in private equity. So if you could comment in terms of what you're seeing, both onshore U.S. and offshore?

Robert G. Gwin
President

Okay. Onshore is easier to talk about because there's a lot more data points than offshore, but I think offshore probably ends up following the same model. Your latter point about capital is the one that's really driving the market today. It is clearly a seller's market today, in our opinion. We bid on a number of asset packages that are out there, and the prices that we understand they're clearing the market for we don't really quite understand. Quite frankly, it seems like there is full value being paid. Especially for oily assets we've seen out there, full value is being paid. I think that's because of the significant amount of capital that's chasing these deals. Everybody's heard rumors of various size. We were hearing $30 billion of private equity, then we heard $100 billion. And the most recent conversation I had with someone said there's $150 billion of private debt and equity, before back-levering, chasing transactions, and over 100 management teams that have private-equity backing that have yet to do a deal. Now I don't know if those numbers are right or not, but I think from a macro standpoint, it tells you that there's a lot of folks chasing a few deals. If you consider what their return objectives are, and if you consider the fact that they need to get money to work in order to start having their reason to exist be worthwhile, then it follows suit that they're going to be pretty aggressive in chasing assets. And so far, we've seen prices out there that we haven't felt like chasing. So what does that mean? What that means is you look more at your own portfolio and say what else might we be willing to sell in the current environment. And certainly, with the packages that we've had out there, we're been very pleased with the bids that we've received. And it doesn't mean we'll necessarily sell a lot more, but it tells us that selling in the current environment is something that is something that we want to continue to pursue. Deepwater or offshore, there's fewer transactions, fewer data points. The place where we get some insight is through some of the farm-outs that we're doing with exploration. We've seen some very strong uptake there. It's a little bit of a different universe of buyers, more operators, but still some private equity-backed folks. They're quite interested in pursuing some of these opportunities. And they tend to like to drill with us because of our success rates historically. Going forward, it seems -- I don't see any reason why that capital is going to dry up, unless commodity prices materially back up and the return potential, even for those private investors, just simply isn't there anymore.

William A. Anthony Featherston
UBS Investment Bank, Research Division

Are there any other questions for Bob?

Robert G. Gwin
President

You guys are letting me off easy. It's good going at 7:30.

William A. Anthony Featherston
UBS Investment Bank, Research Division

Yes. All right, if not, please join me in thanking Anadarko.

Robert G. Gwin
President

Thanks, you guys.

Exhibit 95

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D. C. 20549

FORM 8-K

CURRENT REPORT
PURSUANT TO SECTION 13 OR 15(d) OF THE
SECURITIES EXCHANGE ACT OF 1934

Date of Earliest Event Reported: July 28, 2015

ANADARKO PETROLEUM CORPORATION

(Exact name of registrant as specified in its charter)

Delaware	1-8968	76-0146568
(State or Other Jurisdiction of Incorporation)	(Commission File Number)	(IRS Employer Identification No.)

1201 Lake Robbins Drive
The Woodlands, Texas 77380-1046
(Address of principal executive offices)

Registrant's telephone number, including area code **(832) 636-1000**

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

The information in this Current Report on Form 8-K shall not be deemed to be "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended (Exchange Act), or otherwise subject to the liabilities of that section, and is not incorporated by reference into any filing under the Securities Act of 1933, as amended, or the Exchange Act.

Item 2.02 Results of Operations and Financial Condition.

On July 28, 2015, Anadarko Petroleum Corporation (Anadarko) announced second-quarter 2015 financial and operating results. The press release is included in this report as Exhibit 99 and is incorporated herein by reference.

Item 7.01 Regulation FD Disclosure.

On July 28, 2015, Anadarko provided guidance for the remainder of 2015. This information is contained in the press release included in this report as Exhibit 99.

Item 9.01 Financial Statements and Exhibits.

(d) Exhibits.

99 Anadarko Press Release dated July 28, 2015.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

ANADARKO PETROLEUM CORPORATION
(Registrant)

July 28, 2015

By: /s/ CHRIS CHAMPION
Chris Champion
Vice President, Chief Accounting Officer and Controller

EXHIBIT INDEX

Exhibit No.	Description
99	Anadarko Press Release dated July 28, 2015.

Exhibit 99

Anadarko Petroleum Corporation

NEWS

ANADARKO ANNOUNCES SECOND-QUARTER 2015 RESULTS

Increases Midpoint of Full-Year Oil Sales-Volume Guidance by 15,000 Barrels per Day

HOUSTON, July 28, 2015 – Anadarko Petroleum Corporation (NYSE: APC) today announced its financial and operating results for the second quarter of 2015, including net income attributable to common stockholders of $61 million, or $0.12 per share (diluted). These results include certain items typically excluded by the investment community in published estimates, which in the aggregate increased net income by $57 million or $0.11 per share (diluted).[1] Net cash flow from operating activities in the second quarter of 2015 was $1.243 billion, and discretionary cash flow from operations totaled $1.373 billion.[2]

HIGHLIGHTS

- Increased year-over-year oil sales volumes by 42,000 barrels per day, adjusted for divestitures[3]
- Achieved large-scale project milestones in the Gulf of Mexico and Mozambique
- Announced deepwater exploration success in a frontier basin offshore Colombia
- Announced more than $1.7 billion of monetizations year to date

"During the second quarter, we delivered more than 18,000 barrels per day of higher-margin oil sales volumes above our guidance, driven by continued improvements in productivity and ongoing operating efficiencies," said Anadarko Chairman, President and CEO Al Walker. "The operating improvements achieved to date are contributing to an expected full-year increase over 2014 of 13 percent, or about 35,000 barrels of oil per day, enhancing our relative cash margins and enabling us to drill more than 100 additional wells this year – all while staying within our capital guidance. In addition, we've created significant option value through our exploration success offshore Colombia and in the Gulf of Mexico, and accelerated value through active portfolio management. We believe these actions and differentiating achievements, the depth and strength of our portfolio, and the commitment of our employees, position us well for continued success."

OPERATIONS SUMMARY

During the second quarter, Anadarko's sales volumes of oil, natural gas and natural gas liquids (NGLs) totaled 77 million barrels of oil equivalent (BOE), or an average of 846,000 BOE per day. The company also updated its full-year 2015 sales-volume guidance to a range of 298 million to 302 million BOE, which excludes 2015 sales volumes associated with the divestitures of EOR and Bossier.

In the U.S. onshore, Anadarko increased oil sales volumes by approximately 30 percent year over year on a divestiture-adjusted basis,[3] driven by the Wattenberg field, Eagleford Shale and Delaware Basin, while natural-gas sales volumes were lower, reflecting third-party infrastructure downtime and curtailments, as well as the company's storage program.

During the quarter, Anadarko achieved a significant production milestone, averaging 101,000 barrels of oil per day (BOPD) in the Wattenberg field in Colorado, while also achieving exceptional efficiency improvements. The company has realized a significant reduction in drilling cost per foot over a two-year period and is currently drilling new Wattenberg horizontal wells for approximately $1 million per well. During the second quarter, Anadarko also achieved startup at its 300-million-cubic-feet-per-day (MMcf/d) Lancaster II cryogenic expansion, providing additional growth capacity for the Wattenberg field.

Anadarko expects to achieve its objective of drilling more than 200 wells in the Eagleford Shale this year with fewer rigs than initially anticipated. Efficiency gains are enabling Anadarko to re-allocate rigs from the Eagleford Shale to the Wolfcamp Shale oil play in the Delaware Basin of West Texas. During the quarter, the Delaware Basin increased year-over-year oil sales volumes by almost 30 percent and achieved startup at the 200-MMcf/d Mi Vida cryogenic gas plant.

In the deepwater Gulf of Mexico, Anadarko's Lucius facility achieved name-plate capacity of 80,000 BOPD with production stabilizing during the quarter. The company also continued to advance the 80,000-BOPD Heidelberg spar on schedule with the successful installation of the hull and completion of the topsides.

The Mozambique liquefied natural gas (LNG) project also continues to advance with the selection of a consortium consisting of CB&I, Chiyoda Corporation and Saipem (CCS JV) for the initial development of the onshore LNG park. The scope of the work includes two 6-million-tonnes-per-annum (MMTPA) LNG trains, which is a 20-percent increase in the original capacity expectations with no change to estimated costs.

Anadarko continues an active deepwater exploration program. The company's first well, Kronos, in the frontier basin offshore Colombia, encountered 130 to 230 net feet of natural gas pay in the upper objective, proving the presence of a working petroleum system and validating the company's geologic and seismic interpretations. Drilling is ongoing toward the deeper objective before mobilizing the rig to drill the Calasu prospect, which is also located in the 4.5-million-acre Grand Fuerte Block, approximately 100 miles northeast of the Kronos well. In the Gulf of Mexico, Anadarko spud its third appraisal well in the Shenandoah field and plans to commence drilling on an appraisal well to the previously announced Yeti discovery, which encountered more than 270 net feet of oil pay.

FINANCIAL SUMMARY

Anadarko ended the second quarter with approximately $2.2 billion of cash on hand. Year to date, Anadarko has reached agreements to divest more than $1.1 billion in assets, including the recently announced $440 million divestiture of its Bossier natural gas field and associated midstream infrastructure. In addition, Anadarko accelerated more than $575 million of value from the secondary sale of Western Gas Equity Partners, LP (NYSE: WGP) units and a WGP-linked tangible equity unit offering.

OPERATIONS REPORT

For details on Anadarko's operating areas and exploration program, including tables illustrating same-store sales information,[3] please refer to the comprehensive report on second-quarter 2015 activity. The report is available at www.anadarko.com.

CONFERENCE CALL *TOMORROW* AT 8 A.M. CDT, 9 A.M. EDT

Anadarko will host a conference call on Wednesday, July 29, 2015, at 8 a.m. Central Daylight Time (9 a.m. Eastern Daylight Time) to discuss second-quarter results, current operations and the company's outlook for the remainder of 2015. The dial-in number is 866.777.2509 in the United States or 412.317.5413 internationally. Participants can register for the conference at http://dpregister.com/10068168. For complete instructions on how to participate in the conference call, or to listen to the live audio webcast and slide presentation, please visit www.anadarko.com. A replay of the call will be available on the website for approximately 30 days following the conference call.

FINANCIAL DATA

Nine pages of summary financial data follow, including current hedge positions and updated financial and production guidance.

[(1)] See the accompanying table for details of certain items affecting comparability.

[(2)] See the accompanying table for a reconciliation of GAAP to non-GAAP financial measures and a statement indicating why management believes the non-GAAP financial measures provide useful information for investors.

[(3)] See the accompanying table for a reconciliation of "divestiture-adjusted" or "same-store" sales volumes, which are intended to present performance of Anadarko's continuing asset base, giving effect to recent divestitures.

Anadarko Petroleum Corporation's mission is to deliver a competitive and sustainable rate of return to shareholders by exploring for, acquiring and developing oil and natural gas resources vital to the world's health and welfare. As of year-end 2014, the company had approximately 2.86 billion barrels-equivalent of proved reserves, making it one of the world's largest independent exploration and production companies. For more information about Anadarko and APC Flash Feed updates, please visit www.anadarko.com.

This news release contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Anadarko believes that its expectations are based on reasonable assumptions. No assurance, however, can be given that such expectations will prove to have been correct. A number of factors could cause actual results to differ materially from the projections, anticipated results or other expectations expressed in this news release, including Anadarko's ability to realize its expectations regarding performance in this challenging economic environment and meet financial and operating guidance, timely complete and commercially operate the projects and drilling prospects identified in this news release, consummate the transaction described in this release, enter into a definitive agreement with CCS JV, successfully plan, secure necessary government approvals, finance, build and operate the necessary infrastructure and LNG park, and achieve production and budget expectations. See "Risk Factors" in the company's 2014 Annual Report on Form 10-K, Quarterly Reports on Form 10-Q and other public filings and press releases. Anadarko undertakes no obligation to publicly update or revise any forward-looking statements.

# # #

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Anadarko Petroleum Corporation
Certain Items Affecting Comparability

	Quarter Ended June 30, 2015		
millions except per-share amounts	Before Tax	After Tax	Per Share (diluted)
Total gains (losses) on derivatives, net, less net cash from settlement of commodity derivatives*	$ 229	$ 145	$ 0.28
Gains (losses) on divestitures, net	(91)	(77)	(0.15)
Impairments	(30)	(20)	(0.04)
Change in uncertain tax positions (FIN 48)	—	9	0.02
	$ 108	$ 57	$ 0.11

* Includes $(83) million related to commodity derivatives and $312 million related to interest-rate derivatives.

	Quarter Ended June 30, 2014		
millions except per-share amounts	Before Tax	After Tax	Per Share (diluted)
Total gains (losses) on derivatives, net, less net cash from settlement of commodity derivatives*	$ (237)	$ (151)	$ (0.30)
Gains (losses) on divestitures, net	9	8	0.02
Impairments	(117)	(75)	(0.15)
Change in uncertain tax positions (FIN 48)	—	(115)	(0.23)
Contingent Clean Water Act penalty accrual	(90)	(90)	(0.17)
Interest expense related to Tronox settlement	(19)	(19)	(0.04)
	$ (454)	$ (442)	$ (0.87)

* Includes $(76) million related to commodity derivatives, $(159) million related to interest-rate derivatives, and $(2) million related to gathering, processing, and marketing sales.

Reconciliation of GAAP to Non-GAAP Measures

Below are reconciliations of net income (loss) attributable to common stockholders (GAAP) to adjusted net income (loss) (non-GAAP), cash provided by operating activities (GAAP) to discretionary cash flow from operations (non-GAAP), as well as free cash flow (non-GAAP) as required under Regulation G of the Securities Exchange Act of 1934. Management uses adjusted net income (loss) to evaluate the Company's operational trends and performance.

	Quarter Ended June 30, 2015		Quarter Ended June 30, 2014	
millions except per-share amounts	After Tax	Per Share (diluted)	After Tax	Per Share (diluted)
Net income (loss) attributable to common stockholders	$ 61	$ 0.12	$ 227	$ 0.45
Less certain items affecting comparability	57	0.11	(442)	(0.87)
Adjusted net income (loss)	$ 4	$ 0.01	$ 669	$ 1.32

Anadarko Petroleum Corporation

Reconciliation of GAAP to Non-GAAP Measures

Management uses discretionary cash flow from operations because it is useful in comparisons of oil and gas exploration and production companies as it excludes certain fluctuations in assets and liabilities and current taxes related to certain items affecting comparability. Management uses free cash flow to demonstrate the Company's ability to internally fund capital expenditures and to service or incur additional debt.

	Quarter Ended June 30,		Six Months Ended June 30,	
millions	**2015**	2014	**2015**	2014
Net cash provided by (used in) operating activities	**$ 1,243**	$ 2,462	**$ (3,261)**	$ 4,191
Add back				
Increase (decrease) in accounts receivable	**462**	(83)	**105**	183
(Increase) decrease in accounts payable and accrued expenses	**(84)**	(84)	**199**	(21)
Other items—net	**(339)**	82	**269**	27
Tronox settlement payment	**—**	—	**5,215**	—
Certain nonoperating and other excluded items	**3**	1	**25**	1
Current taxes related to asset monetizations	**88**	56	**316**	576
Discretionary cash flow from operations	**$ 1,373**	$ 2,434	**$ 2,868**	$ 4,957

	Quarter Ended June 30,		Six Months Ended June 30,	
millions	**2015**	2014	**2015**	2014
Discretionary cash flow from operations	**$ 1,373**	$ 2,434	**$ 2,868**	$ 4,957
Less capital expenditures*	**1,401**	2,402	**3,223**	4,970
Free cash flow**	**$ (28)**	$ 32	**$ (355)**	$ (13)

* Includes Western Gas Partners, LP (WES) capital expenditures of $122 million for the quarter ended June 30, 2015, and $173 million for the quarter ended June 30, 2014, $278 million for the six months ended June 30, 2015, and $343 million for the six months ended June 30, 2014.

** Free cash flow for the six months ended June 30, 2015, includes a $595 million current tax benefit associated with the Tronox settlement.

Presented below is a reconciliation of total debt (GAAP) to net debt (non-GAAP). Management uses net debt as a measure of the Company's outstanding debt obligations that would not be readily satisfied by its cash and cash equivalents on hand.

	June 30, 2015		
millions	**Anadarko Consolidated**	**WGP* Consolidated**	**Anadarko excluding WGP**
Total debt	**$ 16,058**	**$ 2,677**	**$ 13,381**
Less cash and cash equivalents	**2,173**	**89**	**2,084**
Net debt	**$ 13,885**	**$ 2,588**	**$ 11,297**

millions	**Anadarko Consolidated**	**Anadarko excluding WGP**
Net debt	**$ 13,885**	**$ 11,297**
Total equity	**19,359**	**16,389**
Adjusted capitalization	**$ 33,244**	**$ 27,686**
Net debt to adjusted capitalization ratio	**42%**	**41%**

* Western Gas Equity Partners, LP (WGP) is a publicly traded consolidated subsidiary of Anadarko and WES is a consolidated subsidiary of WGP.

Anadarko Petroleum Corporation
(Unaudited)

Summary Financial Information *millions except per-share amounts*	Quarter Ended June 30, **2015**	Quarter Ended June 30, 2014	Six Months Ended June 30, **2015**	Six Months Ended June 30, 2014
Consolidated Statements of Income				
Revenues and Other				
Natural-gas sales	**$ 487**	$ 991	**$ 1,128**	$ 2,208
Oil and condensate sales	**1,616**	2,705	**3,035**	5,129
Natural-gas liquids sales	**229**	411	**461**	797
Gathering, processing, and marketing sales	**305**	278	**598**	589
Gains (losses) on divestitures and other, net	**(1)**	54	**(265)**	1,560
Total	**2,636**	4,439	**4,957**	10,283
Costs and Expenses				
Oil and gas operating	**226**	273	**522**	586
Oil and gas transportation and other	**289**	281	**650**	547
Exploration	**103**	502	**1,186**	801
Gathering, processing, and marketing	**255**	250	**509**	502
General and administrative	**278**	305	**588**	603
Depreciation, depletion, and amortization	**1,214**	1,048	**2,470**	2,172
Other taxes	**151**	361	**333**	675
Impairments	**30**	117	**2,813**	120
Deepwater Horizon settlement and related costs	**—**	93	**4**	93
Total	**2,546**	3,230	**9,075**	6,099
Operating Income (Loss)	**90**	1,209	**(4,118)**	4,184
Other (Income) Expense				
Interest expense	**201**	186	**417**	369
(Gains) losses on derivatives, net	**(311)**	323	**(159)**	776
Other (income) expense, net	**15**	(13)	**62**	(12)
Tronox-related contingent loss	**—**	19	**5**	4,319
Total	**(95)**	515	**325**	5,452
Income (Loss) Before Income Taxes	**185**	694	**(4,443)**	(1,268)
Income Tax Expense (Benefit)	**77**	428	**(1,315)**	1,092
Net Income (Loss)	**108**	266	**(3,128)**	(2,360)
Net Income (Loss) Attributable to Noncontrolling Interests	**47**	39	**79**	82
Net Income (Loss) Attributable to Common Stockholders	**$ 61**	$ 227	**$ (3,207)**	$ (2,442)
Per Common Share				
Net income (loss) attributable to common stockholders—basic	**$ 0.12**	$ 0.45	**$ (6.32)**	$ (4.84)
Net income (loss) attributable to common stockholders—diluted	**$ 0.12**	$ 0.45	**$ (6.32)**	$ (4.84)
Average Number of Common Shares Outstanding—Basic	**508**	505	**507**	505
Average Number of Common Shares Outstanding—Diluted	**509**	507	**507**	505
Exploration Expense				
Dry hole expense	**$ 13**	$ 302	**$ 42**	$ 423
Impairments of unproved properties	**18**	109	**998**	186
Geological and geophysical expense	**16**	37	**38**	80
Exploration overhead and other	**56**	54	**108**	112
Total	**$ 103**	$ 502	**$ 1,186**	$ 801

Anadarko Petroleum Corporation
(Unaudited)

Summary Financial Information *millions*	Quarter Ended June 30, **2015**	Quarter Ended June 30, 2014	Six Months Ended June 30, **2015**	Six Months Ended June 30, 2014
Cash Flows from Operating Activities				
Net income (loss)	**$ 108**	$ 266	**$ (3,128)**	$ (2,360)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities				
Depreciation, depletion, and amortization	**1,214**	1,048	**2,470**	2,172
Deferred income taxes	**11**	142	**(1,187)**	188
Dry hole expense and impairments of unproved properties	**31**	411	**1,040**	609
Impairments	**30**	117	**2,813**	120
(Gains) losses on divestitures, net	**91**	(9)	**425**	(1,468)
Total (gains) losses on derivatives, net	**(310)**	325	**(158)**	786
Operating portion of net cash received (paid) in settlement of derivative instruments	**81**	(88)	**172**	(186)
Other	**29**	54	**74**	108
Changes in assets and liabilities				
Deepwater Horizon settlement and related costs	**(3)**	92	**1**	92
Tronox-related contingent liability	**—**	19	**(5,210)**	4,319
(Increase) decrease in accounts receivable	**(462)**	83	**(105)**	(183)
Increase (decrease) in accounts payable and accrued expenses	**84**	84	**(199)**	21
Other items—net	**339**	(82)	**(269)**	(27)
Net Cash Provided by (Used in) Operating Activities	**$ 1,243**	$ 2,462	**$ (3,261)**	$ 4,191
Capital Expenditures	**$ 1,401**	$ 2,402	**$ 3,223**	$ 4,970

millions	**June 30, 2015**	December 31, 2014
Condensed Balance Sheets		
Cash and cash equivalents	**$ 2,173**	$ 7,369
Accounts receivable, net of allowance	**2,602**	2,527
Other current assets	**635**	1,325
Net properties and equipment	**37,820**	41,589
Other assets	**2,474**	2,310
Goodwill and other intangible assets	**6,420**	6,569
Total Assets	**$ 52,124**	$ 61,689
Other current liabilities	**4,578**	4,934
Deepwater Horizon settlement and related costs	**91**	90
Tronox-related contingent liability	**—**	5,210
Long-term debt	**16,025**	15,092
Deferred income taxes	**7,594**	9,249
Other long-term liabilities	**4,477**	4,796
Stockholders' equity	**16,389**	19,725
Noncontrolling interests	**2,970**	2,593
Total Equity	**$ 19,359**	$ 22,318
Total Liabilities and Equity	**$ 52,124**	$ 61,689
Capitalization		
Total debt	**$ 16,058**	$ 15,092
Total equity	**19,359**	22,318
Total	**$ 35,417**	$ 37,410

Capitalization Ratios		
Total debt	**45%**	40%
Total equity	**55%**	60%

Anadarko Petroleum Corporation
(Unaudited)

Sales Volumes and Prices

	Average Daily Sales Volumes			Sales Volumes			Average Sales Price		
	Natural Gas MMcf/d	Oil & Condensate MBbls/d	NGLs MBbls/d	Natural Gas Bcf	Oil & Condensate MMBbls	NGLs MMBbls	Natural Gas Per Mcf	Oil & Condensate Per Bbl	NGLs Per Bbl
Quarter Ended June 30, 2015									
United States	**2,354**	**240**	**130**	**215**	**21**	**12**	**$ 2.28**	**$ 54.14**	**$ 17.98**
Algeria	**—**	**50**	**6**	**—**	**5**	**—**	**—**	**60.24**	**31.11**
Other International	**—**	**28**	**—**	**—**	**3**	**—**	**—**	**61.82**	**—**
Total	**2,354**	**318**	**136**	**215**	**29**	**12**	**$ 2.28**	**$ 55.78**	**$ 18.50**
Quarter Ended June 30, 2014									
United States	2,620	196	119	238	18	11	$ 4.16	$ 98.69	$ 37.39
Algeria	—	72	1	—	7	—	—	108.64	66.69
Other International	—	23	—	—	2	—	—	110.16	—
Total	2,620	291	120	238	27	11	$ 4.16	$ 102.04	$ 37.66
Six Months Ended June 30, 2015									
United States	**2,545**	**238**	**134**	**461**	**43**	**24**	**$ 2.45**	**$ 49.23**	**$ 17.63**
Algeria	**—**	**60**	**6**	**—**	**11**	**1**	**—**	**57.80**	**32.01**
Other International	**—**	**28**	**—**	**—**	**5**	**—**	**—**	**55.69**	**—**
Total	**2,545**	**326**	**140**	**461**	**59**	**25**	**$ 2.45**	**$ 51.37**	**$ 18.24**
Six Months Ended June 30, 2014									
United States	2,658	189	109	481	34	20	$ 4.59	$ 96.86	$ 40.08
Algeria	—	65	1	—	12	—	—	108.60	66.69
Other International	—	27	—	—	5	—	—	109.00	—
Total	2,658	281	110	481	51	20	$ 4.59	$ 100.76	$ 40.22

	Average Daily Sales Volumes MBOE/d	Sales Volumes MMBOE
Quarter Ended June 30, 2015	**846**	**77**
Quarter Ended June 30, 2014	848	77
Six Months Ended June 30, 2015	**890**	**161**
Six Months Ended June 30, 2014	834	151

Sales Revenue and Commodity Derivatives

	Sales			Net Cash Received (Paid) from Settlement of Commodity Derivatives		
millions	Natural Gas	Oil & Condensate	NGLs	Natural Gas	Oil & Condensate	NGLs
Quarter Ended June 30, 2015						
United States	**$ 487**	**$ 1,181**	**$ 213**	**$ 77**	**$ 3**	**$ 2**
Algeria	**—**	**277**	**16**	**—**	**—**	**—**
Other International	**—**	**158**	**—**	**—**	**—**	**—**
Total	**$ 487**	**$ 1,616**	**$ 229**	**$ 77**	**$ 3**	**$ 2**
Quarter Ended June 30, 2014						
United States	$ 991	$ 1,768	$ 404	$ (41)	$ (44)	$ 2
Algeria	—	711	7	—	(5)	—
Other International	—	226	—	—	—	—

Total	$	991	$	2,705	$	411	$	(41)	$	(49)	$	2
Six Months Ended June 30, 2015												
United States	**$**	**1,128**	**$**	**2,121**	**$**	**426**	**$**	**150**	**$**	**5**	**$**	**17**
Algeria		**—**		**629**		**35**		**—**		**—**		**—**
Other International		**—**		**285**		**—**		**—**		**—**		**—**
Total	**$**	**1,128**	**$**	**3,035**	**$**	**461**	**$**	**150**	**$**	**5**	**$**	**17**
Six Months Ended June 30, 2014												
United States	$	2,208	$	3,308	$	790	$	(122)	$	(60)	$	2
Algeria		—		1,293		7		—		—		—
Other International		—		528		—		—		—		—
Total	$	2,208	$	5,129	$	797	$	(122)	$	(60)	$	2

Anadarko Petroleum Corporation
Financial and Operating External Guidance
As of July 28, 2015

Note: Guidance excludes 2015 sales volumes associated with EOR and Bossier

	3rd-Qtr Guidance (see Note)			Full-Year Guidance (see Note)		
	Units			Units		
Total Sales Volumes (MMBOE)	71	—	73	298	—	302
Total Sales Volumes (MBOE/d)	772	—	793	816	—	827
Oil (MBbl/d)	301	—	310	306	—	312
United States	216	—	220	221	—	225
Algeria	58	—	61	62	—	63
Ghana	27	—	29	23	—	24
Natural Gas (MMcf/d)						
United States	2,135	—	2,180	2,305	—	2,325
Natural Gas Liquids (MBbl/d)						
United States	108	—	115	119	—	122
Algeria	6	—	8	5	—	6

	$ / Unit			$ / Unit		
Price Differentials vs NYMEX (w/o hedges)						
Oil ($/Bbl)	(3.70)	—	1.60	(3.90)	—	1.40
United States	(6.00)	—	(1.00)	(6.00)	—	(1.00)
Algeria	2.00	—	8.00	2.00	—	8.00
Ghana	2.00	—	8.00	1.00	—	6.00
Natural Gas ($/Mcf)						
United States	(0.45)	—	(0.35)	(0.45)	—	(0.35)

Anadarko Petroleum Corporation
Financial and Operating External Guidance
As of July 28, 2015

Note: Guidance excludes items affecting comparability

	3rd-Qtr Guidance (see Note)			Full-Year Guidance (see Note)		
	$ MM			$ MM		
Other Revenues						
Marketing and Gathering Margin	30	—	50	140	—	160
Minerals and Other	60	—	70	280	—	300
	$ / BOE			$ / BOE		
Costs and Expenses						
Oil & Gas Direct Operating	3.95	—	4.15	3.45	—	3.75
Oil & Gas Transportation/Other	3.75	—	3.95	3.70	—	3.90
Depreciation, Depletion, and Amortization	15.25	—	15.75	15.40	—	15.70
Production Taxes (% of Product Revenue)	8.0%	—	9.0%	7.5%	—	8.5%
	$ MM			$ MM		
General and Administrative	330	—	350	1,225	—	1,275
Exploration Expense						
Non-Cash	90	—	110	500	—	550
Cash	115	—	135	375	—	400
Interest Expense (net)	200	—	210	805	—	825
Other (Income) Expense	35	—	45	175	—	225
Taxes						
Algeria (All current)	55%	—	60%	55%	—	60%
Rest of Company (35% Current / 65% Deferred for Q3 and Expect Significant Current Tax-Benefit for FY)	35%	—	45%	25%	—	30%
Avg. Shares Outstanding (MM)						
Basic	507	—	508	507	—	509
Diluted	508	—	510	508	—	510
Capital Investment (Excluding Western Gas Partners, LP)	$ MM			$ MM		
APC Capital Expenditures	1,250	—	1,450	5,400	—	5,700

Anadarko Petroleum Corporation
Commodity Hedge Positions
As of July 28, 2015

	Volume (MBbls/d)	Weighted Average Price per barrel					
			Floor Sold		Floor Purchased		Ceiling Sold
Crude Oil							
Three-Way Collars							
2016							
WTI	20	$	45.00	$	60.00	$	67.00
Brent	8	$	50.00	$	65.00	$	75.00
	28	$	46.43	$	61.43	$	69.29

	Volume (thousand MMBtu/d)	Weighted Average Price per MMBtu					
			Floor Sold		Floor Purchased		Ceiling Sold
Natural Gas							
Three-Way Collars							
2015	635	$	2.75	$	3.75	$	4.76
Extendable Fixed Price - Financial							
2015*	170	$	4.17				

* Includes an option for the counterparty to extend the contract term to December 2016 at the same price.

Interest-Rate Derivatives
As of July 28, 2015

Instrument	Notional Amt.	Start Date	Maturity	Rate Paid	Rate Received
Swap	$50 Million	Sept. 2016	Sept. 2026	5.91%	3M LIBOR
Swap	$1,850 Million	Sept. 2016	Sept. 2046	6.06%	3M LIBOR

Anadarko Petroleum Corporation
Reconciliation of Same-Store Sales

Average Daily Sales Volumes

	Quarter Ended June 30, 2015				Quarter Ended June 30, 2014			
	Natural Gas MMcf/d	Oil & Condensate MBbls/d	NGLs MBbls/d	Total MBOE/d	Natural Gas MMcf/d	Oil & Condensate MBbls/d	NGLs MBbls/d	Total MBOE/d
U.S. Onshore	**2,241**	**174**	**123**	**671**	2,443	134	113	654
Deepwater Gulf of Mexico	**113**	**57**	**7**	**83**	176	41	6	76
International and Alaska	**—**	**87**	**6**	**92**	—	101	1	102
Same-Store Sales*	**2,354**	**318**	**136**	**846**	2,619	276	120	832
China, Pinedale/Jonah, and EOR	**—**	**—**	**—**	**—**	1	15	—	16
Total	**2,354**	**318**	**136**	**846**	2,620	291	120	848

	Six Months Ended June 30, 2015				Six Months Ended June 30, 2014			
	Natural Gas MMcf/d	Crude Oil & Condensate MBbls/d	NGLs MBbls/d	Total MBOE/d	Natural Gas MMcf/d	Crude Oil & Condensate MBbls/d	NGLs MBbls/d	Total MBOE/d
U.S. Onshore	**2,378**	**171**	**127**	**694**	2,420	123	102	628
Deepwater Gulf of Mexico	**167**	**51**	**7**	**86**	225	43	6	87
International and Alaska	**—**	**97**	**6**	**103**	—	95	1	96
Same-Store Sales*	**2,545**	**319**	**140**	**883**	2,645	261	109	811
China, Pinedale/Jonah, and EOR	**—**	**7**	**—**	**7**	13	20	1	23
Total	**2,545**	**326**	**140**	**890**	2,658	281	110	834

* Same-store sales for the periods ended June 30, 2015 and June 30, 2014, includes sales volumes related to Bossier as the divestiture was not announced until July 2015.

Average Daily Sales Volumes

	Year Ended December 31, 2014			
	Natural Gas MMcf/d	Crude Oil & Condensate MBbls/d	NGLs MBbls/d	Total MBOE/d
U.S. Onshore	2,311	136	111	632
Deepwater Gulf of Mexico	196	45	5	83
International and Alaska	—	94	3	97
Same-Store Sales**	2,507	275	119	812
China, Pinedale/Jonah, EOR, and Bossier	82	17	—	31
Total	2,589	292	119	843

** Same-store sales for the year ended December 31, 2014, excludes sales volumes for the recently announced Bossier divestiture, which is consistent with the 2015 third-quarter and full-year sales volumes guidance provided in this release on page 10.

Exhibit 96

Company Name: Anadarko
Company Ticker: APC US
Date: 2015-07-29
Event Description: Q2 2015 Earnings Call

Market Cap: 38,405.72
Current PX: 75.60
YTD Change($): -6.90
YTD Change(%): -8.364

Bloomberg Estimates - EPS
Current Quarter: -0.463
Current Year: -1.948
Bloomberg Estimates - Sales
Current Quarter: 2509.889
Current Year: 10120.091

Q2 2015 Earnings Call

Company Participants

- John M. Colglazier
- Robert A. Walker
- Darrell E. Hollek
- Robert G. Gwin
- Robert P. Daniels
- James J. Kleckner
- Unverified Participant

Other Participants

- Evan Calio
- Doug Leggate
- Brian A. Singer
- David R. Tameron
- Scott Hanold
- Charles A. Meade
- David William Kistler
- Paul B. Sankey
- John Herrlin
- Edward Westlake
- David Martin Heikkinen
- Mike Scialla
- Robert Christensen

MANAGEMENT DISCUSSION SECTION

Operator

Good morning, and welcome to the Second Quarter 2015 Anadarko Petroleum Corporation Conference Call. All participants will be in a listen-only mode. [Operator Instructions] After today's presentation there will be an opportunity to ask questions. [Operator Instructions] Please note this event is being recorded.

I would now like the turn the conference over to John Colglazier. Please go ahead, sir.

John M. Colglazier

Thank you, Dan. Good morning, everyone, and we're very glad you could join us today for Anadarko's second quarter 2015 conference call.

I'd like to remind you that today's presentation includes forward-looking statements and certain non-GAAP financial measures. And a significant number of factors could affect our results materially from what we discuss today, we encourage you to read our full disclosure on forward-looking statements and the GAAP reconciliations located on our website and attached to yesterday's earnings release.

Additionally we have provided more detail on quarterly operations reported on our website. At this time I'll turn the call to Al Walker and we'll open up the lines in a few minutes for Q&A with Al and our executive team. Al?

Robert A. Walker

Thanks, John. And I think as you recall from our first quarter earnings call, we've approached this year with caution given the volatility of commodity prices and as an opportunity for Anadarko to capitalize on the depth and strength of our portfolio. The achievements today had far surpassed our expectations and this is largely a result of the efforts and commitments of our employees. We continue to focus on enhancing cash margins and portfolio value, which has resulted in tremendous growth in our higher margin oil sales volumes. Full-year sales volume expected to be above our additional guidance by approximately 20,000 barrels per day with reductions in nearly every expense category and continued strong safety performance, or specifically we've driven our drilling costs down in the Wattenberg field by almost 30% odd in the last six months and doubled our rig efficiency over the last year, drilling the same number of wells with half the rigs.

In the Delaware Basin, we've reduced drilling costs by about $0.5 million per well and completions by nearly 45% year-over-year. Our efficiencies and savings will enable us to drill more than 100 wells this year with that current capital expectations and with no belief that we're going to increase our capital plans beyond initial guidance through the balance of the year.

In addition to the short-cycle successes I just described, we're also continuing to make excellent progress on our mid-cycle opportunities, while achieving strong results with our deepwater exploration program. Of particular note, in Colombia, we're very excited about potential of our first well in this offshore frontier basin. As mentioned in our ops report, we have encountered 130 C to 230 C of net pay to what we believe to be in the natural gas prone objective. With additional work once we've finished the well, we'll better understand this discovery. Our joint operations are continuing as we're now looking to test the next lower objective. Along with our partner, Ecopetrol, we look forward to further update on our front as well once we've completed it and moved the rig to our next prospect about a 100 miles away.

About two weeks ago, I had the opportunity to visit with President Nyusi in Mozambique. We discussed the excellent progress that has been made by all parties in the negotiation of various agreements supporting the plan of development to be submitted in the coming month. We are very encouraged with these developments and how they've positioned the project for FID, while in government approval of the POD.

Turning to the financial results. We finished the quarter again in very strong financial condition, as you can see from our earnings release. This financial position was enhanced by accelerating more than $575 million of value from our MLP franchise to a secondary sale of WGP units and an innovative structure for WPG Linked Tangible Equity Units, which we believe to be an offering that we hope to continue to do in the future. I'm very pleased with these achievements so far in 2015. I have the confidence in our ability to continue delivering attractive returns, future growth when economics are more optionality to our exploration and ongoing portfolio management. Coming to the first half of the year, we'll continue to focus the next six months on improving our cash margins and creating value in our portfolio.

I'm going to stop here, but before I open it up for questions, I'm going to take a moment to introduce Darrell Hollek today. Darrell has the unenviable task of succeeding Chuck Meloy, who he believes the legend in our business in the role of leading our onshore E&P efforts. As you can see from the Q2 results the handoff has gone well and we're delighted to have Darrell join us today. So with that, let's go to questions.

Q&A

Operator

We will now begin the question-and-answer session. [Operator Instructions] Our first question today comes from Evan Calio of Morgan Stanley. Please go ahead.

<Q - Evan Calio>: Hi, good morning, guys and great results today. My first question really phenomenal improvements and relatively improvements and efficiencies in the quarter and year-over-year, as highlighted in the Wattenberg, really two questions here. I mean, where do you see the limits on efficiencies and cost savings from here? And secondly what drives until your decision to recycle efficiency gains in the CapEx versus potentially reducing CapEx given the current in forward commodity curves?

<A>: Okay. Well, I appreciate the questions and thank you for the nice comments. I think probably best that Darrell and I tackle this together. Let me just say as it relates to the latter point. I think we believe that we're investing our cash at very attractive rates of return. I think you've heard us talk many, many times about the fact that the Wattenberg area being enhanced by the Maryland interest that we have there coupled with the efficiencies associated with what we have done to date and have done so well historically.

We are continuing to put capital there and we'll continue even in 2016 and what is now continuing to be a lower price environment. One that, I'm sure recall, we were pretty cautious about last time we were to get around our first quarter earnings call.

But I think as it relates to the Wattenberg in particular, the only constraint we have there is, just trying to state as close as we can, overall the investing capital is close to our discretionary cash flow for the year. The rates of return are very attractive and that's the reason you see us continuing to do things that we do in that asset.

I'll let, Darrell, if you don't mind address the first half of the question.

<Q - Evan Calio>: Okay.

<A - Darrell E. Hollek>: Yeah. In terms of your question on efficiency, you know, it's hard to imagine how much further we can go. The things really surprises us every quarter, and we've continued to go down. If you listen those comments about our drilling performance, where we've now been able to get our well cost replace the drilling portion down to less than $1 million a copy.

And so, there's a lot of really good work in terms of how we designed our well and how we reduced our non-productive time while drilling, and then obviously we had some vendor reductions. But, when you get down to the May and copy, we're now drilling these wells and in five days or less, and we've just started there, we've got about 50 wells like this.

So we'll continue to move our other rig lines towards that, but what that really does for us is it allows us to drill considerably more wells, in this case we're in 70 wells as compared to what we were doing a year ago at 35.

And so, is there a room, I hope so in this commodity market. We're going to continue to push forward. But the team, again has done a great job and you know aside from there, if you look at the completions, they've done a really nice job there as well getting our cost down. So for about $3.5 million, now we're drill complete and then equipping these wells.

But I do want to send that to those our midstream group as well, we've put on $90 million of compression in the first quarter. We did that again in the second quarter. So bringing down those line pressures, it's really helping our volumes as well, so it's sort of a team effort down in that area.

<Q - Evan Calio>: That's great. That's helpful. And then a second question if I could on Mozambique. Is the decision – then I appreciate the update. I mean, is the decision to FID the project by year-end, conditioned on either owning any reduced interest or upon the commodity outlook at the time. And I know your economics are underpinned by long-term contracts, post 2020 on a turnkey EPC contract, but you're obviously your future cash flows are effected by any protracted downside. So any kind of color there, as we move into the back-half of the year, it'd be helpful?

<A>: Sure. And I can understand some of the questions. I will say, I think, we've reiterated before interests in selling down from here approaches zero, from the standpoint that we believe that we're going to be in this project, we're one of the operator. And so selling down additional interest below where we are today will put into question whether or not we will be operator so.

Just pure arithmetic of it doesn't have any interest from that perspective. As it relate to gating issue to get into FID and I think the biggest gating issue I can highlight for you would be just getting the plan of development approved by the government. In some ways, we have some control over that as through this middle process and the things that lead up to it. But in terms of actually having the government approve the POD, that would be the biggest gating issue leading to FID.

<Q - Evan Calio>: Great. And what drove the kind of free upsizing under that turnkey contract by the EPS firms. Was that a concern about rebid or can you discuss that at all.

<A>: Yeah. So, the question is Mrs. Jim, what drove the upsizing on the size of the liquification trains. We ran a competitive feed for the liquefaction facilities and during that comparative feeds, the consortiums that we're in, the process have made advancements to engineering and technologies where they could upscale the capacity of the plant.

And so those plants which were originally targeted for 5 million tons per annum per train, were upsized essentially to 6 million tons per annum. They had installed and designed plants like that in the past at Papua New Guinea, it was a good example of the most recent LNG facility. And so, those efficiencies were factored in and we received upsized plants or trains in this case for similar 5 million ton per annum costs.

<Q - Evan Calio>: Got it. I appreciate it guys. Thank you.

<A>: Yeah. Thanks for the question.

Operator

Our next question comes from Doug Leggate of Bank of America Merrill Lynch. Please go ahead.

<Q - Doug Leggate>: Look, good morning, everybody. Hi, all. Can you hear me, okay?

<A>: Yes, sir. Absolutely, thanks, Doug.

<Q - Doug Leggate>: No worries, good to know. Just a couple of quick questions, please. So, first of all on disposals, the Bossier sale that you obviously had a fairly good price in the – just towards of [indiscernible] the quarter. I guess is not completed, yet. But when I look through the ops report, I see a number of other areas that don't have current rig activity. I guess, one such would come to mind, Marcellus would come to mind and obviously there is a couple of others you get and so on.

So I'm just kind of wondering, what your non-core asset disposal program is for things like Ozona one, such as Marcellus and so on, and what process you happen to currently. And I've got a follow-up.

<A - Robert G. Gwin>: Hey, Doug its Bob Gwin. Good question, that will decline to address relative to the specific assets that we're looking at, but from a philosophical standpoint, you're look at the portfolio the way that we do, we're look at non-core assets and the fact that we think – and at least currently this remains a seller market, they're a lot of assets there are not going to attract capital at our portfolio, but still have really nice return characteristics and economics. And quite a bit of tail left on them, and those assets are attractive to some others. And so we continue to look at the broader portfolio, try to determine which ones we would like to hang to as a part of our future inventory, and which ones we think might be better owned by someone else. We've got a couple of processes underway currently and we're going to continue to refine and upgrade the portfolio. Our view is, we can take the proceeds from those types of asset sales, redeploy it in not only our onshore shorter cycle opportunities but some of these mid longer cycle opportunities, that's a significant value creator from a macro standpoint.

<Q - Doug Leggate>: Bob, – well I hope you then – the process I think Bossier as I understand, it was something close to 100 folks interested in the data room and the way it was characterized to me at least to us, above from short pricing through 3P resource evaluation, obviously you got a great price for it. But how would you characterize the current M&A environment for assets, is it still that healthy?

<A>: Well, we certainly think and hope so, but obviously with commodity prices backing up fairly shortly on a percentage basis. More recently than the time that we were marketing that Bossier asset, we'll see, if each assets' unique, specifics relative to the asset and its specific location within these various basins and the amount of capital chasing the opportunities relevant to the asset we're selling is really the determining factor in terms of how strong your bid process is. We don't expect we'd sell everything that we would target, we would look to see if we think the sales price is attractive and we've got one we're pretty close on now, its relative small and from a macro standpoint this is good for us. Because it helps us to clean up the portfolio, reallocate not only our capital but our people and our attention on the things that are going to add the most value.

<A>: Doug, this is Al, let me just add on the buy side of that same commentary. We've been reasonably unsuccessful, if I can use that as a term, in trying to buy things from the Delaware Basin where I think we have a cost advantage, we're clearly through Western Gas have a processing advantage and yet we see time and again, people coming in there and buying things and at prices that surprises. I will also say that we've been – we bought fairly aggressively on a couple of things and were bid or rather we were outbid by 2X. So to Bob's comment, it seems to be a seller's market, and even in an area where I would say we have significant advantages in terms of both geological and economic, we're still not a successful buyer in a asset that we would like to add to but only at the right price.

<Q - Doug Leggate>: I appreciate the answer. My follow-up is hopefully a little quicker. Again in the ops report, a lot of discussion about some of the really interesting exploration success you've had, but to this strike me as kind of significant buy, the fact that we've not included is Coronado. Given your lease win recently on Phobos, I am just wondering if you could share your latest thoughts from those two and I'll leave it there.

<A>: Yeah, Doug, it's Bob. Coronado is part of the Shenandoah mini-basin. We've got a discovery there that we've apprised. So we think we've got pretty good handle on what it is. We recently picked up some blocks again. We have some expiries that we had to put back in and then picked them back up, and that's going to stay that way until we have Shenandoah development plan put in place because we see it as a tie back through that facility. The other one that you mentioned was Phobos?

<Q - Doug Leggate>: Phobos, yeah.

<A>: Phobos, we're looking at potential appraisal well in early 2016, we're trying to get all our partners aligned, get their views on what the – how they see it. And then, get that into the drilling schedule. That's being worked, as we speak.

<Q - Doug Leggate>: Bob, did your working interest in Coronado move up?

<A>: Yes, it did.

<Q - Doug Leggate>: Can you quantify it?

<A>: I don't remember the exact number, but it did move up.

<Q - Doug Leggate>: Okay. Have a good day guys. Thanks so much.

Operator

Our next question comes from Brian Singer of Goldman Sachs. Please go ahead.

<Q - Brian A. Singer>: Thank you. Good morning. With the additional wells that you're drilling is the result of efficiency gains this year. And an increase in the backlog of drill, but uncompleted wells, it seems like you have a lot of flexibility to turn the machine back on when you see fit. Can you just talk to that what you are looking for in the commodity markets, your balance sheet and your CapEx cash flow profile, assuming the current cost structure holds to more aggressively began completing that backlog?

<A>: Go ahead.

<**A - Robert P. Daniels**>: Yeah. This is Daniels, Brian. Again because we have drilled the wells, we are going to have a significant uplift and what we would call the docks the drill, but uncompleted. We went on last quarter saying we'd probably carry over a 125 in the next year and as we see it now, we'll probably going to do – carry over around 200, but I would say based on your comments we, we do tend to be very flexible here. We'll probably stand up at least one completion rig, and complete some of the extra wells being drilled. Going in to the year, we've pulled down capital. We went from four completion crews down to one in Wattenberg as we speak today. But we'll be standing one up in August and beyond that. We'll be flexible to just see what our needs are.

<**A**>: And as it relates to more of the balance sheet and how we might fund such things Brian, with the asset sales that we're pursuing and the fact that even just on a clean basis, we basically spent within cash flow on the most recent quarter. We've got the flexibility to use our cash position if we choose to. But that's going to be driven by the economics available of completing and pursuing those wells, and what environment we're selling that flush production into.

<**Q - Brian A. Singer**>: So, do you think about bold enough being CapEx, cash flow in neutral post asset sale, pre-asset sale or some around in between?

<**A**>: Yeah, no. I would say certainly neutral or better when include asset sales. And if you look at our original guidance for the year, we were essentially looking at funding our CapEx program this year with our cash flow as plus the sale proceeds from the EOR transaction to $700 million earlier this year. Obviously, we've done well at continuing to monetize things beyond that, that gives us even more flexibility. And of course, we're pretty focused on keeping that balance sheet healthy and very cognizant of what our leverage position is because no one knows what the depth or where the length of the commodity price downturn is going to look like. So, we're trying to just maintain flexibility, but obviously we have the ability to turn up this figure, both from a cash standpoint and from an opportunity standpoint if and when the economics warranted.

<**Q - Brian A. Singer**>: Thanks. That's great. And then my follow-up actually goes back to the – to Doug's question earlier on the M&A environment where he characterizes a seller's market. I think the focus though on, what you were talking about there was on buying or selling assets with equity valuations having come down. Can you just talk about whether – how do you look at the corporate environment, where do you see corporate valuations attractive, where there is more of an opportunity to buy companies versus to buy assets here, and maybe on the other side where – what your view is on where the major stand on taking the greater interest in U.S shale?

<**A**>: We look as lots of corporate opportunities. Obviously, we like most companies, have screening tools and look at relative value differential between how our equity trades and potential target equities trade. Asset values are high, corporate values are low, that would lead one to believe that the opportunities, the better opportunities made this from a corporate standpoint. However, few corporate opportunities are actually perfect fits from a portfolio perspective, so you introduce execution risk and whether or not you're making your company as efficient on a pro forma basis as it is going into a transaction.

So we consider all those things and look at it, and we – we'll see the – it's going to be an interesting second half of the year here driven by commodity-price environment and if the market stays relatively weak than obviously the opportunity to do something might go up. But, we're just trying to remain flexible enough to take advantage of opportunity if it exists. You're latter question on the measures, I don't know, I mean it's hard to know what they're thinking of and what they're looking at. So we're just trying to focus on where we can build the best company and hopefully be as attractive to all our shareholders as possible.

<**A**>: Brian, now let me just add one thing or two to Bob's comments which I think he represents the views of us quite well on the topic you're asking about. As it relates to an M&A transaction, and I'll go back to a comment I've made on prior calls. And that is, our objective is to get better not bigger, and if getting bigger allows us to get better then that's okay, we like the position we've got, we like the assets we're in, we like the exploration opportunities that we have in-house. If we see a company that has assets that are complementary, then I think that would cause us to take a harder look at them, but just buying somebody that's distressed with assets that don't fit the piece of the puzzle the way we see the puzzle looking, probably should be considered way outside the white stakes.

<Q - Brian A. Singer>: Thank you very much.

<A>: You bet.

Operator

And our next question comes from David Tameron of Wells Fargo. Please go ahead.

<Q - David R. Tameron>: Good morning. Yeah, congrats on a nice quarter. Colombia? Can you just give us Colombia with a – oh, not you. Can you just give us your thoughts on Colombia and what you're seeing thus for and just a quick pick there?

<A>: Yeah David, its Bob. So we're on the first well, Kronos we announced. So we found between 130 and 230 to pay in the upper objective of that well. And the reason for the range is that's some lemonade stand sands, low contrast, and so we're waiting on for some rock data. We think that – we're confident of the 130, and we think the 230 is very realistic also, but we don't want to get over our skies and so we know really what we've got there. It is all gas charged, but we – David anytime that we go into a frontier basin and your first well in the first objective finds what you're kind of looking for, we're very, very encouraged with it.

And then when we look at what the gas is telling us, it does look like its originally thermogenic, but it was thermogenic liquids, that have been biodegraded given the temperatures that we're seeing here, and the depth of this is at. All of the geo-chemistries seems to be indicating that, which is an indirect evidence that we do have an oil generating system that matches in with our petroleum systems work and the temperatures that we're seeing. We are not seeing a hot basin here, like we're seeing in Mozambique.

We are seeing increasing, heavier components, as we go deeper in the well bore. We have not seen any direct evidence of oil at this point, but all the indirect evidence is pointing to very consistent with our original pre-drill estimates, that this should be an oil prone system and the shallower objectives very similar to what we see in Eastern belt of Mexico. We are seeing biodegraded thermal liquids and that turns into methane.

So, everything we're seeing today is extremely encouraging. We've got to get down to the second objective here. We just have geomechanical issues. We've got to work our way through to get this well down. But we're making progress and then move up to Calasu, which is a 100 miles away on the same blocks. And still we have there in a very different play style, but as we've always said we've got multiple play styles, multiple objectives out here. This is a huge acreage position with about 6 million acres down in the Fuerte area, about 10 up in the COL area. And so, we've got a lot of running room here and we're very, very encouraged with what we've seen.

<Q - David R. Tameron>: Thanks. Good detail. And then what's the – remind me what's the drilling obligations now here?

<A>: This is our obligation on the Fuerte Sur Block and then the Calasu will be the obligation well in the Fuerte Norte Block, and that's our obligation.

<Q - David R. Tameron>: Okay.

<A>: We are planning on next year coming back and probably appraising Kronos. And then we're putting together rest of drilling schedule in Colombia.

<Q - David R. Tameron>: Okay. Thanks. And then I'm going to go back to the CapEx. I just want to make – I'm just trying to get you guys' thoughts. Obviously, you're a leader in the industry, as goes – the sentiment right now goes to group. But I'm just trying to figure out, if you think about 2016, if you think about rest of this year obviously like you mentioned Bob, your plus or minus cash flow right now at least in this quarter. If you end up – if this is to continue, you obviously don't want to get your dock number to 400. Like how do you think about that balance you spend that additional CapEx if there is such a thing this year, doing more exploration. And I'm just trying to think about how you

guys picture the environment right now and then what do you see is the likely outcome for as you roll into 2016? I know obviously it's all price dependent, but I'm just trying to get more clarity?

<A>: Well, for 2015, as Al mentioned earlier, we have no expectations of increasing the capital budget this year and obviously, we had the opportunities to decrease it, but we're just getting a lot more done for the same dollars this year. When we look to 2016 that was going to be based upon 2016 cash flow. Certainly, we expect to see some proceeds from asset sales. We feel pretty good about the ability to continue to move either through the tangible equity units or direct secondary sales continue to move additional of our WGP holdings in the market. So, it's going to be – the opportunity is going to be available to us just spend more money in 2016 in our spend cash flow. But as we get some little bit better clarity on where we think that little bit of cash flow number is going to look like in 2016. We're going to be working with the board to decide whether it's within cash flow or something in excess of, either way we expect it will be able within cash flow plus asset sale proceeds. And so, therefore, we'd avoid putting any pressure on the balance sheet or adding any incremental financial risk to the company's profile.

<Q - David R. Tameron>: Okay. That's one – and one follow-up, and then I'll jump off. So, I think about it today obviously, Niobrara with the royalty exit that works and you made the comment earlier, economic sense. Today, at the strip with current service cost, with current efficiencies as of today, does it make sense to – like how do you think about economic sense in that snapshot today?

<A>: So, we could on the margin, obviously, we could on the margin push on that production accelerator somewhat in the Ladenburg. The economics are intrinsically attractive and then when you include the royalty component, and that's pretty attractive there. I would imagine it's one of the better assets in North America from a return standpoint today. However, those are also your Tier 1 assets and some of the best assets in the portfolio, that the margins on those assets were substantially higher in the past. We've talked in the past about 100% type rates of return just last year. And so, while we are comfortable continuing to work down that drilled non-completed inventory somewhat, working down aggressively in an environment where we are earning fewer absolute dollar margins per barrel solely to achieve a growth objective that we don't believe is terribly valued in the current environment. It doesn't seem to make the most sense. And it's an option for us and it's an option, we might choose to pursue if we thought the current environment was going to be protracted and we were somehow in a new normal in this $50 oil environment. We don't believe that to be intermediate to longer term. So we believe there is more value in moderating the production growth in the current environment and accelerating in the future when the value is there.

<A>: David. Can I just add one thing to Bob and that is, we think that this business is a margin business, not as a top line business. So therefore the price doesn't trigger, meaning the hydrocarbon price doesn't trigger our net interest and capital allocation. It's really the margin and I don't need to explain to you or probably folks on the call, but the velocity change in the hydrocarbon price is greatly exceeded the velocity change that we realized to date on service cost.

So we scaled even with the tremendous amount of hardship that service providers have gone through in the first half of the year. We as upstream company, still don't have the margin we had a year ago and don't have a margin that gives us the kind of return that I think would prompt us to believe that we need to go back into a growth mode and I think just to lever the point a little further, we still see the uncertainty that we made reference to in the first quarter with respect to sustainable prices giving us an encouragement to go back into the growth mode and don't think this year is likely to create that and we're going to watch what happens this year as hopefully an indication of what we might think for 2016.

<Q - David R. Tameron>: Okay. All right, I took more than my time. Thanks.

Operator

Our next question comes from Scott Hanold of RBC Capital Markets. Please go ahead.

<Q - Scott Hanold>: Thanks. Good morning, guys. It seems Delaware Basin is getting a little bit more attention from you all this quarter. If I step back and look at last quarter, it seems like reduced some of the focus on it in part because of infrastructure constraints, can you all give us an update on is there, it could be incremental capital going there, even

at these prices say into 2016?

<A>: Well, I think the reason you're hearing a little more volume, is that we are turning up the dial a little bit on that, simply because we got more drilling results. We also, if you recall late last year, made a very attractive acquisition via Western Gas for additional infrastructure. That infrastructure is, we have done in the western playbook for the Wattenberg, is very key to the way we think about a very major development opportunity in the basin that today is still in the early stages. I also made reference to the fact that while we think we have a unique position to be able to be a consolidator there, to date, we've not seen opportunities to pick up properties that we otherwise would like to see, just simply because there is more capital chasing this than we think is reasonable.

That said, I think definitely again very large position we had going into this before anyone knew anything about it, it has now become a very well known play and certainly the attention that it has received from lots of private equity back firms as well as public traded firms. Is why you're hearing more volume from us, and more volume from others and I think Darrell can give you a little bit of color as to why we're seeing some of that for what it makes for Anadarko to put capital towards it. Because again our capital has to compete on an internal rate of return basis with other place to invest and today behind the Wattenberg, the Permian Basin and particularly the Delaware portion of the Permian Basin has a co-position in the number two spot. So Darrell?

<A>: Yeah. I think Al sums it up well, but this is an area you're going to hear a lot about from us and from industry. It's just huge and if you look at our position, we've had seven rigs running out here now and we talked about some of the efficiencies we've picked up in Wattenberg. But our drilling efficiencies have actually picked up in all of our locations, including Eagle Ford and Delaware and so we do have some what we think room in terms of where we're spending our capital. So we're actually moving a rig as we speak into Delaware, an eighth rig and we may yet move a ninth one over there. And we're not into the point that we're doing pad drilling yet and we're still learning a lot about the acreage we have because we got a really position here. But I can tell you we're pretty excited about what we're seeing. We've got one completion crew there now, and there is a good chance we'll stand up a second completion crew there as well as we drill additional well. But that's again that's going to part of that flexibility as we play out the rest of the year, but that's a really exciting area for us and everything we're finding is encouraging and I would say even from last year, our well cost have gone down a $1 million on the drilling and completion side. So we've got a lot of really good things happening in that area and I think you can expect to continue to hear a lot about Delaware from us.

<Q - Scott Hanold>: Yeah. More specifically with – obviously you address the cost side of things, but on well performance side, what have you seen incrementally. Do you have some color around that and I know you all were looking at the Wolfcamp A, as well as the Bone Spring formation. Is there an update on how some of those pallets have gone?

<A>: Our focus right now is the Wolfcamp A, that's what you're seeing all of our drilling right now. I can tell you though we have drilled Bone Springs 2, well you're hearing about that from industry, while we've got – while we build about a 100,000 acres of Bone Springs 2 sitting on our acreage as well. We've drilled that well. But it won't get completed until August. So, those results will be forthcoming in the second half of the year. But what we're seeing in the Wolfcamp A again continue to be pretty consistent across our acreage. And so, that's really encouraging for us.

<Q - Scott Hanold>: Yeah, and I guess I misspoke, I meant the Lower Wolfcamp Bay; I think you're looking at the upper end of Lower Wolfcamp Bay. Have you kind of defined the opportunity between those two formations?

<A>: Not yet. But one of the reasons we are looking to bring additional rigs in there is to make sure we're testing all the horizons. So, you should see some results coming in the future on that.

<Q - Scott Hanold>: Okay. I appreciate that. Thanks.

Operator

Our next question comes from Charles Meade of Johnson Rice. Please go ahead.

<**Q - Charles A. Meade**>: Yes, good morning, everyone. Al, I know you've – you and your team there have already heard a lot of questions on your CapEx, partially going forward. And I think this may be a case of no good deed going unpunished, since last quarter you guys had the compression call of not wanting to accelerate. And noting that you thought there was a possibility pricing, oil prices can head back down. But you mentioned that, I think I've heard you correctly that you said that you didn't – you did not foresee in the back half of 2015 the conditions coming around where that would lead you to want to accelerate. But can you share with us again since you have the hot hand right now; it seems, on looking at the oil market, what is it – what's your outlook for 2016? How long do you think it's going to be before you can – you can – put more money back to work either on your operations or the A&D front on the asset side specifically?

<**A**>: While I appreciate the comments, those are not necessarily mine, I'd say it was faults collectively of our management team, I just happen to make them that particular day. As it relates to how we think about allocation of capital the second half of the year, I'll come back to a comment I made a few minutes ago. And it's really more about the margin and not about the hydrocarbon price. We still see some improvement from the service sector in terms of our abilities to improve margins.

I think there are a lot of things we've done that are permanent, as it relates to the efficiencies that we've put in place. So it's not just price reductions from various service vendors that in a different hydrocarbon price environment would come back to us at a higher price, these are actually sustainable improvements that we'll weather the storm of higher prices when we have those. So it's really looking at the margins that we anticipate from our major asset plays through the balance of the year, looking exactly what we've think we can achieve with those. And it just seems unlikely to the six of us today that we're going to have the kind of margins that we have seen historically, that would encourage us to go back in to a growth mode. I think there are going to be asset plays, we've talked about two of them in particular today, and the Delaware Basin and the DJ Basin, that we believe even in the environmental we're in provides us a rate of return from what we see from – what we get from the upstream and mid-stream capabilities of the organization. That's probably a place where we can say with some confidence, we'll put capital. But I'm not sure, we as a company and I don't believe, we as an industry are anywhere close to the types of margin improvement that's needed before we go back into a growth and growth would have been in turn be rewarded by investors.

<**Q - Charles A. Meade**>: Got it. So, Al, would – is it a reasonable timeframe for when you start to look at 2016 sometime this fall is when you started that, that comes into focus?

<**A**>: Well certainly, I think you should anticipate that not just Anadarko, but we all don't look at things quarter-to-quarter or year-to-year I mean we do multiyear planning and we do sensitivities around those and yet with the shale plays in particular I think all of you are quite attuned to the fact that they deplete 50% to 80% in the first year, so there we had to be very confident of the margin environment that we're moving into, because we're not going to be able to capture that on the back side of the well, since so much of the production would have occurred. So that's why I'm a little hesitant and cautious about exactly when we'll see this company in particular and industry more broadly be encouraged to go back into a growth mode.

<**Q - Charles A. Meade**>: Thank you, Al. That's helpful. And then moving onto kind of asset specific question. I know the old beach you had in Q2 you mentioned the Wattenberg, but it seems like the Gulf of Mexico also played a significant part of that and I'm curious how much of that – how much of this – the outperformance on the oil side in the Gulf of Mexico was one-time so to think related to the timing or the ramp up of Lucius and how much of that is going to – how much of that is a contributor to your durable guide up for the back half of the year?

<**A**>: Well, we're very fortunate that we believe that there is a cocktail out there, that's a mix of unconventional and conventional that makes sense for the way in which we think about the business plans that we develop. And I think you're right, you hit on the fact that Lucius is our nameplate capacity that's important, but we don't model it, Jim will walk you through and talk a little bit, I mean we got a lot out there and a lot of this goes back to exploration successes that have come out of the Bob Daniels world and the deepwater exploration in the past and we continue as you know from this quarter to how things that we do out there in the deepwater and exploration success framework. So we think that will continue to do things. So Jim, if you don't mind just talk a little bit about where we are on the trajectory?

<**A - James J. Kleckner**>: Right, the performance in the Gulf of Mexico has been meeting expectations on the all fronts. Recently, we just bought the Lucius facility on and that hit our expectations right on the mark. The facilities win in as scheduled. Production ramped up to our name play capacity. We brought in third-party gas across the facility over 300 million cubic feet a day from South Hadrian. So process handling agreements and cash flow looks very strong. Following that, we have Heidelberg coming on. So we're expecting the Heidelberg field to first a well in mid part of 2016. The Heidelberg spar has been set in all the mooring lines from install, so it's storm already. The topside has been fully commissioned and the [ph] Ingel side yard side here. And it will be scheduled for lift out, beginning October when the heavy lift barge the Heerema shows up. So that's all progressing very well. That's we have our projects lined up. We also are looking in-field opportunities throughout the Gulf of Mexico that increased production some of our legacy field. So we see strong performance to the Gulf, and it could really buy economical projects that we've taken commercial opportunities on to reduce interest for carried capital rates, as we done in the past Lucius and Heidelberg.

<**Q - Charles A. Meade**>: Thank you, Jim.

Operator

Our next question comes from Dave Kistler of Simmons. Please go ahead.

<**Q - David William Kistler**>: Good morning, guys. Real quickly, I guess, last quarter you guys updated us in terms of maintenance CapEx, necessary to keep production flat. Early in the year, you had about $3 billion, and then you contacted that range to 7 to 9. Based on the continued efficiency gains and cost improvement, where do you see that today, and maybe where do you see that for 2016 just as we try to frame-up outlook.

<**A**>: Well, I think given the really impressive efforts that have come out of our supply change management and what we believe is still fruit that can be picked from the tree that in that range that we gave you previously, you should anticipate will be towards the lower end of that range around 27.

<**Q - David William Kistler**>: Okay, I appreciate that. And then switching over to the Wattenberg just for a second. You indicated that production is expected to plateau for the balance of the year. Does that factor in the added compression that should release some of the pressure on wells to allow them to flow more freely or is that just potential upside that could come along with it?

<**A - Darrell E. Hollek**>: Yeah. I think – this is Darrell. I think the benefit of the additional compression was really seen in the first quarter and second quarter. How we play out of the rest of the year, and obviously I mentioned we were gone from four completion complexion rigs down to one we'll will be standing up another one here in the third quarter.

But how the rest of the year plays out, really depends on how we handle these ducts in these additional wells that are currently being drilled. So right now its forecasted to decline a little bit, but we can turn that around fairly really quickly and that's what we've decided to do. And we're probably looking to do some of that as we go into 2016.

<**Q - David William Kistler**>: Okay, I appreciate that. And then maybe just one last one. Thorvald, it's my understand they didn't hit TD on that. Can you talk a little bit about the decision on maybe going back and pushing the drill bit that gain based on what you've seen seeing today if there?

<**A**>: Yeah. We didn't get to our ultimate objective there. Again, geomechanics in the wellbore design, we had to stop. So we're taking all the day that we've acquired thus far, reintegrating into our seismic interpretation and looking at what the potential , but what we didn't see could be what the potential of what we found, it could be and where we may want to drill out the second well, and whether that's the right thing to do. We are the operator of the prospect now, that was part of the deal that we had originally as we got 50% working interest and operator shifts. So that's our call as we move forward and you probably hear more about that later.

<**Q - David William Kistler**>: Okay. I appreciate that color. Thanks, guys.

Operator

Our next question comes from Paul Sankey, of Wolfe Research. Please go ahead.

<Q - Paul B. Sankey>: Good morning, everyone. You've talked about cash flow neutrality, can you just run us through your cash flow and CapEx for this quarter, because I'm just seeing a slightly low relative to CapEx. So could you just talk me through, you mentioned earlier, a clean number, I think is what you said in terms of how we should look at the quarter and cash flow? Could you just walk through some of the elements of that and whether or not that's still a representative quarter given that it was about a $60 oil price and that's basically what we see on the strip, right?

<A>: Yeah, Paul. I think you're hitting a very important point. I think we were – we did a really good job in the second quarter, keeping our CapEx was in a close zip code of cash discretionary cash flow. We don't believe that prices are likely to improve from here. So, therefore it will be more challenging in the couple of quarters ahead of us to continue to have that more neutral cash flow to CapEx. I think the amount of erosion that we would see are deficit free cash flow is not significant. And some of this will have to do, we're just going to a comment Darrel made a few minutes ago, about just how much drill is uncompleted. We want to take into next year's inventory versus how much of that would be available to us if we saw a different price environment as I keep reiterating this morning of better margin environment, in order to produce into.

So I think while we had great success in the first half of the year, quite proud of the way in which the organization responded to the market environment and the way in which the second quarter produced out. Given where we are at this point in the year, where we see the second half of the year being, we would be very challenged to continue to be cash flow neutrality like we were in the second quarter relative to CapEx and expect CapEx probably slightly outpace cash flows through the balance of the year.

<Q - Paul B. Sankey>: Okay. So what you kind of saying is basically that it is fairly represents to no more than $1.2 billion of cash flow $60, I guess, obviously it would add in any growth you've achieved and then a margin improvement, I suppose the other aspect of – how to think about it.

<A>: Yeah. I really would tell you. I'm so pleased with and could not be happy relaying, which we've improved our margins. We've also increased our mix and as I made comments too earlier on this call, in my prepared remarks, we see our oil production going up through the balance of the year. So that's favorable mix improvement coupled with further improvements in the margins on the cost side and the efficiency side, I think, we'll renewed our benefit to be able to keep that gap between discretionally cash flow and CapEx. As none of all in terms of the delta possible.

<Q - Paul B. Sankey>: Yeah. Fully understood. And the maintenance CapEx number that you just spoke about. Could you just rationalize the fact that you're saying you really not in growth mode. I guess, it looks like a much lower potential CapEx number, if that maintenance CapEx number that you just gave us is the face of that number?

<A>: Yeah. I think, you're going to appreciate. We like some, but unlike a lot, commit to a lot medium cycle as well as long-cycle spending in our total CapEx. And so we will continue to find exploration in an environment where we believe the option value there is worth a lot to us. Same thing, this is the mid-cycle thing that we'll do in the Gulf of Mexico that we have not going into detail on this call. But just simply, there is the types of things that will increase our oil production in the intermediate cycle that are quite attractive to us. There's a right thing to spend capital loan because of the rate of returns that we achieved.

So when we think about being in that 2, 7 range with maintaining the volumes, you should anticipate that we don't believe natural gas production will increase over the second-half of the year, but rather it will continue to decrease and that we hope to offset that with attractive oil margins and oil production.

<Q - Paul B. Sankey>: Perfect. Thank you. That's helpful.

<A>: You bet.

Operator

Our next question comes from John Herrlin of Société Générale. Please go ahead.

<Q - John Herrlin>: Yeah. Hi. Two quick ones, Bob for Kronos, were you basically saying you found C3 and C5 with the gas?

<A>: No. In the upper objective we can see once. But the chromatograph and the geochemical analysis says, good in ward dividends that it is derived from thermogenic, liquid thermogenic fluids. And that – then that's been biodegraded and it's in that temperature windows that would allow for biodegradation, very, very similar to what we saw in all of the eastern Gulf of Mexico, in the shallow Miocene gas discoveries.

<Q - John Herrlin>: Good. Thanks. One question on the Wattenberg, I'm trying to be get worse in terms of the incremental docs. Is the issue relatively valued or due to the infrastructure or combination of both because obviously if you have lower line pressures you get more volume and output.

<A>: Honestly, and I don't think you're going to be surprised by my answers. It's all driven by value. I think what we did with Western Gas and the infrastructure that we've put in place, the additional infrastructure that we make reference in the ops report coming on line from a takeaway capability and capacity. But I couldn't be more pleased with the way in which our midstream operations have handled that. I think that will be a pretty good precursors, John for how we anticipate the Delaware to play out as well.

And I think the capital that we will continue to invest behind system and the equity should bode well as we think about Western gas and Anadarko and the years ahead. I think in addition, it's simply we don't anticipate whether it's in the DJ or in the Delaware to get into a situation where we're going to be capacity constrained around facilities that we operate. The amount of oil ultimately gets produced out of Delaware. I'll just say the midstream industry in general is going to have to find some relief for the oil that needs to move into the Gulf Coast and I think there's plenty of pipelines have been proposed so far, so that one doesn't worry me, but as it relates to the midstream capabilities that we have, I think we've been head of the curve both in the DJ and we're ahead of the curve again in the Delaware.

<Q - John Herrlin>: Okay.

<A>: I got a – I wanted to comment on there, John. When you looked at the first half of the year by far it was that $180 million of compressions impacting it, but we'll see the benefit toward the rest of the year. The one thing we didn't mentioned is we stood at Lancaster too as well, that gives us another $300 million of processing capacity and so the real point there is that's our second Lancaster plant, that's up. We got $600 million of capacity now in processing, and so the infrastructure is staying ahead of us out there, so although we're drilling at a little bit faster pace than we anticipated because of the synergies, we don't feel that we're going to be restrictive there. And so let me decide to put that money to work against the completions, we'll have the ability to raise those volumes pretty quickly.

<Q - John Herrlin>: Great. Thanks. That's what I wanted to hear. Thank you.

Operator

Our next question comes from Mark Lear of Credit Suisse. Please go ahead.

<Q - Edward Westlake>: Hello. It's Ed Westlake. I hope you can hear me. Can you hear me?

<A>: Yeah.

<Q - Edward Westlake>: Okay. Good morning. So just to classify, you're putting some mix to work in the Delaware and obviously a lot of people think that's a huge prolific and large play and you were very clear about what you're doing at the moment. But what are the key gating factors for you to really accelerate in the Delaware aside from quantity of price?

<A>: Well, I think it's just simply a matter of, Darrell's got a lot of area there that he's still trying to figure out the early extent of the play and so there is a little bit of understanding what we have in the way of total volumes and the recoverability of those volumes, we've done a little beta testing with how we could anticipate a development plan to work, but I think as you can probably appreciate, this is not a blanket shale, it's not a blanket reservoir. And so areas that it will actually perform a little bit differently than others and so we're in the data collection mode and not all of it in the near-term will go into that manufacturing or development mode. Darrell, through that, through that.

<A>: Yeah, I mean unlike Wattenberg you got to remember you don't have any of the infrastructure out in Delaware as you do – that we enjoy there in Wattenberg. Although picking up that midstream component last year was significant, but there's still a lot of pipe to get out. We put the beta plan on this year, that's going to help, but we still have a lot of infrastructure to put in place. And so, we expect our volumes to continue to go up. Like I said, we're moving the rig in there. We're likely to move – stack in additional rig this year. But we still have a lot to learn on the different zones, if you will, and over the 230,000 net acres that we have, but I wouldn't expect us to get into a pad drilling mode anytime yet this year because there's just so much infrastructure yet and so much to learn before we really go down that path. So I would look to – closer to 2016 sometime before we start getting into that mode.

<Q - Edward Westlake>: like the – I like the beta testing, that's a technology terminal, I don't see a lot of technology in this industry, but – and this maybe a long shot, would you be able to at this point as you think about your beta test development plan, talk about where you think the D&C cost could get down to and sort of EURs and potential to oil or is it too early, I mean we see a lot of results across the industry, so we can make up our own minds but I'd just be intrigued just to where your head was out for some of those key metrics?

<A>: I would say it's early, for sure, we looked at those last year, we dropped cost about $1 million per well on the drilling and completion side. So there's no doubt in my mind that we've got a learning curve, yet we're going down and we'll get those costs down further than that. If you look at what we continue to do at Wattenberg, we've been there long time and we continue to get those costs down. So I think it's going to be an evolution. As we learn what works best out here. So I think you could anticipate not only ourselves but industry will get better in drilling and completing wells out there. So I'm pretty encouraged what the cost structure could look like out there.

<Q - Edward Westlake>: And to be provocative and switch topics on the learning curve, some folks say the offshore is dead. I mean, I have my own view, you have yours, you've laid them out pretty clearly. But how low do you think you could lower the breakevens on some of these larger discoveries in the Gulf of Mexico and hopefully Fuerte [indiscernible] Colombia to make this competitive with, with what's going on in say, strip pricing today?

<A>: Well, let me try if I can to answer part of this along with Jim. Part of this has to do with whether or not we are able to tie that to the existing infrastructure.

<Q - Edward Westlake>: Yeah.

<A>: If we are able to do that, that helps a lot of work, we're able to do what we did with Lucius and Heidelberg and that's design one and build two and reduce cost there substantially, that helps again.

I think you've seen us, time and again, tieback to existing infrastructure and that sort of a opportunity that few people have, I'm not saying that we're completely unique in the regard, but there's not that many others have infrastructure to tieback into.

Now, if you're talking about drilling something that has no infrastructure, obviously it's going to have a bigger EOR, therefore the breakeven is a little bit different, and that's very different in the Gulf of Mexico than it would be in West Africa, because basically you're drilling deeper wells in different environment, and we see that in some other places.

So, maybe with that, that's a good handle for me to let Jim give you a little more color around that.

<A - James J. Kleckner>: I think Al covered it pretty well with that. What I would add to that would be we aren't seeing the price response as dramatic in the deepwater larger or mega projects spaces what we're obviously seeing in our onshore business.

We are however seeing some price retractions, obviously through the deepwater rig fleets, pricing has dropped. So, that's allowing us to curve back some savings. But what we're really looking at is what is the subsea infrastructure manufacturing and then the large offshore facility costs, and those are seeing some reductions. And so, we're incorporating those into our field development plans.

But we're very fortunate with the – that of Daniel's exploration group has done a great job in identifying high-quality developments. And so, with a combination of those resources and with some of the price recoveries we're seeing, and I think coupled with our project management oversight and approaching some of these developments in a minimalistic approach, keeping it constant and keeping it simple, we're able to see some pretty good economics going forward.

<Q - Edward Westlake>: Okay, that's great. Probably a topic for the whole call. But thank you very much.

Operator

Our next question comes from David Heikkinen of Heikkinen Energy Advisors. Please, go ahead.

<Q - David Martin Heikkinen>: I would..

[indiscernible]

<A>: David, don't even go there, just go ahead.

<Q - David Martin Heikkinen>: So, just thinking about additional sources of cash inflows, I was curious about your thoughts on the size of the TEU market per year after the success you had in the second quarter?

<A>: Dave, it remains to be seen. Obviously, we had some really good success with the initial issuance; we ended up doing a transaction that was a lot of interest and an upside that we were very pleased with. As that security matures and gets a little more reputation amongst that higher community, we expect that they will like what they see and we're going to be able to access it again. The other dynamic around the west WGP rather monetization is that the more – the more liquidity that's out there in these securities be the TEUs or WGP itself, then the relative larger size transaction is going to be – you're going to be able to accomplish relative to the flow that's out there. So, we can't predict too aggressively, but it's fair to say that we have some really high expectations for being able to access that market in the future because of the transaction really hits the mark on those – on what those investors desire.

From our standpoint, it's just – it's – we'll still be secondary offerings to WGP from time to time. We'll access the TEU market and it just gives us a broader – a broader market to sell into since our position is so substantial, and it's clearly our desire to continue to access the capital markets through that – those securities in the future.

<A>: David, let me just add real quickly also. I may just comment, I just think it's worth reiterating. We see Western Gas, our monetization efforts there as the source of capital that will fund what we do with the equity portion of the development in Mozambique. So, we're not in a need to quickly liquidate Western Gas in order to achieve that, but that is our source of capital and that would in turn be the use of the capital. Meaning that's extremely important to highlight, simply because we're not looking at cash flow from operations to fund investments in Mozambique, rather that will fund totally the types of E&P activities as you normally and would traditionally think of. And therefore getting into the market with these TEUs, coming up with a structure that have been previously used with c-cores but not used with MLT's and frankly Bob, and his staff and Mike Pearl in particular came up with something introduced that to a market that had been seen before and we're really pleased with what was there.

I just think this continues to be important for us to highlight that we've a great successful Western Gas, we continue to expect Western Gas to play an important role in which we think off the Anadarko and it's midstream integration with its upstream, but hence we think about the GP, The Western Gas that will be continue to be the source of funding in the near-term for how we will make the equity investments Baltimore and Mozambique.

<Q - David Martin Heikkinen>: All right. Thanks guys. And then just cash margin wise, I've heard some work over and had operating cost savings in second quarter and your guidance comes back up. Can you talk regionally of how

those costs came down and then had the ability to sustain that better margin, just from the operating cost standpoint?

<**A**>: David, some of the work over numbers that we're again – are really time dependant in Gulf of Mexico and when we decided to position a rig. So I think our costs were going to be in line or what our projections are and depending on what happens with well float in response for instance, in iHub we lost one of the key gas producing wells and we've brought in a rig and shipped to the sleet and we completed that pull. So, that was an unforeseen work over that we brought in, the well was recovered and we anticipate good flow rates from that well and are in the process of testing it right now.

<**Q - David Martin Heikkinen**>: Okay. Helpful. And then cash sustainability on the – I want to talk a little bit about NGL pricing and then kind of sustainability on the position of process or reject and again just thinking about cash margins in context of your NGL pricing?

<**A**>: Well, you can imagine and we think how the NGL prices a lot, and we'll have Scott Moore who runs marketing for us address that. But NGL volatility this year may have exceeded volatility in any other hydrocarbon and it's certainly been something we had to be mindful of.

<**A**>: Scott, I would also add that until we have rejected about 30 million barrels with NGL this year, but the key point for us is really controlling the value chain and let's just get a relatively stronger realization than we otherwise would, fundamentals remain challenging and we exercise the auction volume in the portfolio as best we can.

<**Q - David Martin Heikkinen**>: So, no expectation of a price recovery or change in volatility, I guess, it is what I should read in that?

<**A**>: Well, I think, that's fair, David, I think we're going to – I'm going to mirror parrot in a lot of comments. I mean, most people see propane obviously heading into heating season and improving. So, that portion of the value chain, it certainly looks like it's got some fundamentals, but if you were just looking at ethane, I can't give you a good pretty picture on ethane.

<**Q - David Martin Heikkinen**>: Yeah. All right. Thanks, guys.

Operator

Our next question comes from Mike Scialla of Stifel. Please go ahead.

<**Q - Mike Scialla**>: Yeah. Good morning. Darrel, you talked about drilling most of the new wells in Wattenberg in five days, which would seem to suggest maybe that further efficiency gains there are kind of limited. Given that, could you talk about the decision to drill primarily short laterals there, I think about 70% of this year's program are actually short laterals. It seems to me that maybe long laterals are the next step change in efficiency there.

<**A**>: Yeah. A lot of that really had to do with the land position, but as we cored up with Noble, I think what you can expect to see is the mid laterals. Those are what we're finding, that probably be the sweet spot, not that we haven't drilled some longs we have, but we've tended to find ourselves getting into some drilling issues. And so from an economic perspective and trouble time, we really think the sweet spot is going to be those mid-laterals.

<**Q - Mike Scialla**>: Okay, thanks. And then sticking with Wattenberg, any idea of when you'll be able to talk more about spacing there? I think you were guiding to kind of 12 wells per section on average. I think you've tested tighter net, any more you can say on that at this point?

<**A**>: Well, for the most part we're 12 wells to 16 wells per section, but again we got a lot of acreage and so not all acreage is equal and we do have a lot of tests going on, up as high as 32 wells per section. And so we're still playing around with that a little bit. But again that's going to be sort of area specific across such a big acreage holding. And – but we're still seeing encouraging results. We think we can get a little bit tighter spacing, but time will tell verdict is out on that just a little bit. We're working between both the Codell and Niobrara as well.

<**Q - Mike Scialla**>: Okay. And then just last one for me. Any thoughts on the – some folks are testing the upper Eagle Ford; I think you guys did a little bit of work there, but any thoughts on that?

<**A**>: Yeah, we're testing that as well. We're actually somewhat encouraged. We've drilled almost two dozen wells of which we've just completed a few and put them online. We've got others to put online, and so we're looking at testing what we call both the upper and sort of middle Eagle Ford if you will, there is a transition zone in there. And so it's too early to tell any results right now. But I'd tell you we're pretty encouraged by it. We have drilled one Buda well, but we are probably not as infatuated with Buda as we are with the both upper and middle Eagle Ford, that you'll continue to hear more information as we get these things tested. But we are, like I said, we probably drilled 24 of those already.

<**Q - Mike Scialla**>: That's all from me. Thank you.

Operator

And our next question comes from Bob Christenson of Imperial. Please go ahead.

<**Q - Robert Christensen**>: Yeah. Thank you. Did I hear Bob that you are going to return the Kronos and drill an offset well next year. Did I mistake that?

<**A**>: No. Bob, this is CFO. And that's our plan right now. We're still trying to figure out our total drill schedule, but the rig this in Colombia now is going to drill – finish Kronos, go over to Calasu and then it's going across to West Africa to [indiscernible] and do DST there, and then, we're looking at okay, what supply in up for next year and high on that list could be Kronos, appraisal well.

<**Q - Robert Christensen**>: Wow, that's a encouraging. Has any high impact exploration less the schedule, much like, you know we saw with Conoco. Is there anything that have been severed from your schedule of thoughts of ideas here that was on the bubble?

<**A**>: No. I think, this has been a little bit of sliding. Our Kenya [indiscernible] well was originally on the schedule for 2015, and that's really all around rig timing, nothing to do with the prospect itself.

But other than that now, we've continued our program, we've had have looked for partners on something and have been successful on that. Again we talk about what our Anadarko capital is versus what our total capital spend is and we're bringing our partners on a promoted basis to some of our opportunities and get us back to kind of what Jim said, if you got quality opportunity, there're still a market out there for them.

<**Q - Robert Christensen**>: And just a final, if you – if I may, I see what's happening with all the things currently in the Gulf of Mexico and in your ops from port support. But what sort of next in the Deepwater Gulf of Mexico, beyond Shenandoah, beyond the appraisal of Yeti. So what's in line in the next six months nine months?

<**A**>: Yeah, we've got couple of other prospects that are on the drill schedule. I think OPEL is one that is a new play type, kind of I wouldn't say it's a frontier basin, but it's a frontier play within that basin. We've got another one called Haleakala, that we're moving forward. I mentioned the Phobos appraisal. So those types of things, we've got deep inventory, we're maturing things as we go. And then we're learning also from the wells we drill, and drilling them back and to see what other opportunities that may lead to.

<**Q - Robert Christensen**>: And OPEL is the big stereographic test, if I recollect?

<**A**>: That's correct.

<**Q - Robert Christensen**>: Okay. Great. Thank you.

<**A**>: All right. Thank you.

Unverified Participant

Well, I think with that we have gone through all the folks in the queue for questions. And I just like to ramp up by saying a couple of things. One, you can anticipate that this management team will continue to watch all oil production in the U.S. does.

The last time we were on this call, we were at about 9.4 million barrels a day. I think as most of you know we're at 9.7 million barrels today. That was one of the reasons we were being very cautious last quarter. We did not see the drop off occurring in the second quarter. At some point the lack of capital being deployed into assets in the U.S. will cause 9.7 million to decline. I think like others, we'll continue to watch that in terms of understanding, how to deploy capital, as simple as that. I mean that we think – one of the most important things we do as the management team made good capital call and I think historically we've done a pretty good job of that.

We will be driven as I mentioned earlier by attractive rates of return. So when we deploy capital we were deploying in the place that we believe gives us some very attractive rate of return. You can also expect that we will and continue to be if not the most active manager of our portfolio one of the most. I can't imagine in the last six or seven years, and you buy this more actively manage the portfolio than we've been. I think as you think about growth, as I made the comment we will have growth when the economics warrant. And we will give you some view of that when we start to see it. And lastly, we will continue to do the things that we did really well historically, particularly when we think back to the 2008 or 2009 period, where we were not going through one of the more robust periods in our industry. We committed significant dollars to exploration and we're doing that again because we like the optionality that comes with exploration and I'll reiterate, we're very excited about the successes we've had in the quarter. And then particularly what we're seeing in offshore Columbia.

So with that – we all appreciate each and everyone being on the call today. We cannot say thank you enough for the support we get from a number of our investors and we look forward to seeing you in the coming weeks and months. Thank you.

Operator

The conference is now concluded. Thank you for attending today's presentation. You may now disconnect.

Exhibit 97

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D. C. 20549

FORM 8-K

CURRENT REPORT
PURSUANT TO SECTION 13 OR 15(d) OF THE
SECURITIES EXCHANGE ACT OF 1934

Date of Earliest Event Reported: October 27, 2015

ANADARKO PETROLEUM CORPORATION
(Exact name of registrant as specified in its charter)

Delaware	1-8968	76-0146568
(State or Other Jurisdiction of Incorporation)	(Commission File Number)	(IRS Employer Identification No.)

1201 Lake Robbins Drive
The Woodlands, Texas 77380-1046
(Address of principal executive offices)

Registrant's telephone number, including area code **(832) 636-1000**

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

The information in this Current Report on Form 8-K shall not be deemed to be "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended (Exchange Act), or otherwise subject to the liabilities of that section, and is not incorporated by reference into any filing under the Securities Act of 1933, as amended, or the Exchange Act.

Item 2.02 Results of Operations and Financial Condition.

On October 27, 2015, Anadarko Petroleum Corporation (Anadarko) announced third-quarter 2015 financial and operating results. The press release is included in this report as Exhibit 99 and is incorporated herein by reference.

Item 7.01 Regulation FD Disclosure.

On October 27, 2015, Anadarko provided guidance for the remainder of 2015. This information is contained in the press release included in this report as Exhibit 99.

Item 9.01 Financial Statements and Exhibits.

(d) Exhibits.

99 Anadarko Press Release dated October 27, 2015.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

ANADARKO PETROLEUM CORPORATION
(Registrant)

October 27, 2015

By: /s/ CHRIS CHAMPION
Chris Champion
Vice President, Chief Accounting Officer and Controller

EXHIBIT INDEX

Exhibit No.	Description
99	Anadarko Press Release dated October 27, 2015.

Exhibit 99

Anadarko Petroleum Corporation

NEWS

ANADARKO ANNOUNCES THIRD-QUARTER 2015 RESULTS

HOUSTON, Oct. 27, 2015 – Anadarko Petroleum Corporation (NYSE: APC) today announced its financial and operating results for the third quarter of 2015, including a net loss attributable to common stockholders of $2.235 billion, or $4.41 per share (diluted). These results include certain items typically excluded by the investment community in published estimates, which in aggregate decreased net income by $1.877 billion or $3.69 per share (diluted), on an after-tax basis.[1] Net cash flow from operating activities in the third quarter of 2015 was $1.127 billion, and discretionary cash flow from operations totaled $979 million.[2]

HIGHLIGHTS

- Exceeded the midpoint of guidance by 6,000 barrels per day of higher-margin U.S. oil sales volumes
- Achieved capital expenditures and lease operating expense (LOE) per barrel of oil equivalent (BOE) below the low end of guidance
- Completed a successful appraisal test at the Shenandoah field in the Gulf of Mexico
- Accomplished a project milestone at the Heidelberg spar with the setting of the topsides
- Continued to actively manage the portfolio by monetizing nearly $2 billion of assets year to date

"We remain committed to building and preserving value in this challenging environment," said Anadarko Chairman, President and CEO Al Walker. "During the third quarter, we continued our focus on maintaining long-term flexibility, while enhancing short-cycle returns by delivering higher-margin sales volumes for lower costs. Our employees have continued to do outstanding work optimizing our performance by moderating our base decline, safely improving efficiencies and rig productivity, and achieving greater cost savings. These efforts and achievements have us well positioned to create differentiating value today and to accelerate activity when the market begins to reward growth again."

OPERATIONS SUMMARY

During the third quarter, Anadarko's sales volumes of crude oil, natural gas and natural gas liquids (NGLs) totaled 73 million BOE, or an average of 787,000 BOE per day. These results include an increase in oil sales volumes of 11,000 barrels of oil per day (BOPD) on a divestiture-adjusted basis[3] over the third quarter of 2014. Anadarko also updated its full-year 2015 sales-volume guidance to a range of 290 million to 292 million BOE, which excludes 2015 sales volumes associated with the divestitures of EOR, Bossier and Powder River Basin coalbed methane (CBM).

In the U.S. onshore, Anadarko increased oil sales volumes by 11 percent year over year on a divestiture-adjusted basis.[3] In the Wattenberg field, Anadarko increased oil sales volumes by 14 percent versus the third quarter of 2014. During the quarter, the Wattenberg team continued to achieve significant improvements in its drilling metrics. As a result, drilling cycle times were reduced by approximately 20 percent with a corresponding 15-percent reduction in drilling costs per foot versus the second quarter of 2015.

Anadarko continues to position its extensive Delaware Basin Wolfcamp Shale opportunity for future oil growth. As a result of improved well recoveries, now approaching 1 million BOE per well, and efficiency gains and cost reductions in the Wolfcamp Shale, this emerging oil play is beginning to contend with Wattenberg in terms of the most attractive economics in the company's U.S. onshore portfolio. Anadarko has successfully reduced drilling costs in the Wolfcamp Shale to around $7.5 million per well with the expected ability to achieve further reductions of $1.5 million to $2 million per well with a future move to field-wide pad drilling. During the quarter, the company also successfully drilled its first test well in the Second Bone Spring, which demonstrated an initial production rate of more than 1,000 BOPD.

In the Gulf of Mexico, the company continued to successfully advance the Heidelberg project with the installation of the topsides. With the significant milestones achieved to date, first oil at Heidelberg has been accelerated and is now anticipated in the second quarter of 2016 from the first three subsea wells, with production from two additional wells coming on line at a later date. Also in the Gulf of Mexico, the company's third appraisal test of the Shenandoah discovery encountered more than 620 net feet of oil pay, and an appraisal well at the Yeti discovery was spud during the third quarter.

OPERATIONS REPORT

For additional details on the operations described above and other operating areas and exploration activities, please refer to Anadarko's comprehensive report on third-quarter 2015 activity. The report is available at www.anadarko.com.

FINANCIAL SUMMARY

Anadarko ended the quarter with $2.1 billion of cash on hand. Year to date, Anadarko has reached agreements to monetize or closed asset monetizations totaling approximately $2.0 billion, including the recent Powder River Basin CBM upstream divestiture, which closed Sept. 1, and the associated CBM midstream transaction, which is expected to close in the fourth quarter.

CONFERENCE CALL *TOMORROW* AT 8 A.M. CDT, 9 A.M. EDT

Anadarko will host a conference call on Wednesday, Oct. 28, 2015, at 8 a.m. Central Daylight Time (9 a.m. Eastern Daylight Time) to discuss third-quarter results, current operations and the company's outlook for the remainder of 2015. The dial-in number is 866.777.2509 in the United States or 412.317.5413 internationally. Participants can register for the conference at http://dpregister.com/10073998. For complete instructions on how to participate in the conference call, or to listen to the live audio webcast and slide presentation, please visit www.anadarko.com. A replay of the call will be available on the website for approximately 30 days following the conference call.

FINANCIAL DATA

Nine pages of summary financial data follow, including current hedge positions, a reconciliation of "divestiture-adjusted" or "same-store" sales, and updated financial and production guidance.

(1) See the accompanying table for details of certain items affecting comparability.

(2) See the accompanying table for a reconciliation of GAAP to non-GAAP financial measures and a statement indicating why management believes the non-GAAP financial measures provide useful information for investors.

(3) See the accompanying table for a reconciliation of "divestiture-adjusted" or "same-store" sales volumes, which are intended to present performance of Anadarko's continuing asset base, giving effect to recent divestitures.

Anadarko Petroleum Corporation's mission is to deliver a competitive and sustainable rate of return to shareholders by exploring for, acquiring and developing oil and natural gas resources vital to the world's health and welfare. As of year-end 2014, the company had approximately 2.86 billion barrels-equivalent of proved reserves, making it one of the world's largest independent exploration and production companies. For more information about Anadarko and APC Flash Feed updates, please visit www.anadarko.com.

This news release contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Anadarko believes that its expectations are based on reasonable assumptions. No assurance, however, can be given that such expectations will prove to have been correct. A number of factors could cause actual results to differ materially from the projections, anticipated results or other expectations expressed in this news release, including Anadarko's ability to realize its expectations regarding performance in this challenging economic environment and meet financial and operating guidance, timely complete and commercially operate the projects and drilling prospects identified in this news release, achieve further drilling cost reductions, consummate the transaction described in this release, and achieve production and budget expectations. See "Risk Factors" in the company's 2014 Annual Report on Form 10-K, Quarterly Reports on Form 10-Q and other public filings and press releases. Anadarko undertakes no obligation to publicly update or revise any forward-looking statements.

# # #

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Anadarko Petroleum Corporation
Certain Items Affecting Comparability

millions except per-share amounts	Quarter Ended September 30, 2015 Before Tax	After Tax	Per Share (diluted)
Total gains (losses) on derivatives, net, less net cash from settlement of commodity derivatives*	**$ (360)**	**$ (227)**	**$ (0.45)**
Gains (losses) on divestitures, net (after noncontrolling interest)	**(613)**	**(388)**	**(0.76)**
Impairments			
Producing properties	**(758)**	**(479)**	**(0.94)**
Exploration assets	**(787)**	**(698)**	**(1.38)**
Inventory adjustments	**(33)**	**(22)**	**(0.04)**
Change in uncertain tax positions (FIN 48)	**—**	**(28)**	**(0.05)**
Other adjustments	**(40)**	**(35)**	**(0.07)**
	$ (2,591)	**$ (1,877)**	**$ (3.69)**

* Includes $46 million related to commodity derivatives, $(407) million related to interest-rate derivatives, and $1 million related to gathering, processing, and marketing sales.

millions except per-share amounts	Quarter Ended September 30, 2014 Before Tax	After Tax	Per Share (diluted)
Total gains (losses) on derivatives, net, less net cash from settlement of commodity derivatives*	$ 276	$ 175	$ 0.35
Gains (losses) on divestitures, net	726	647	1.27
Impairments	(394)	(249)	(0.49)
Change in uncertain tax positions (FIN 48)	—	(60)	(0.12)
Third-party well and platform decommissioning obligation	(22)	(14)	(0.03)
Interest expense related to Tronox settlement	(19)	(12)	(0.02)
	$ 567	$ 487	$ 0.96

* Includes $371 million related to commodity derivatives, $(96) million related to interest-rate derivatives, and $1 million related to gathering, processing, and marketing sales.

Reconciliation of GAAP to Non-GAAP Measures

Below are reconciliations of net income (loss) attributable to common stockholders (GAAP) to adjusted net income (loss) (non-GAAP), cash provided by operating activities (GAAP) to discretionary cash flow from operations (non-GAAP), as well as to free cash flow (non-GAAP) as required under Regulation G of the Securities Exchange Act of 1934. Management uses adjusted net income (loss) to evaluate the Company's operational trends and performance.

	Quarter Ended September 30, 2015		Quarter Ended September 30, 2014	
millions except per-share amounts	After Tax	Per Share (diluted)	After Tax	Per Share (diluted)
Net income (loss) attributable to common stockholders	**$ (2,235)**	**$ (4.41)**	$ 1,087	$ 2.12
Less certain items affecting comparability	**(1,877)**	**(3.69)**	487	0.96
Adjusted net income (loss)	**$ (358)**	**$ (0.72)**	$ 600	$ 1.16

Anadarko Petroleum Corporation

Reconciliation of GAAP to Non-GAAP Measures

Management uses discretionary cash flow from operations because it is useful in comparisons of oil and gas exploration and production companies as it excludes certain fluctuations in assets and liabilities and current taxes related to certain items affecting comparability. Management uses free cash flow to demonstrate the Company's ability to internally fund capital expenditures and to service or incur additional debt.

	Quarter Ended September 30,		Nine Months Ended September 30,	
millions	**2015**	2014	**2015**	2014
Net cash provided by (used in) operating activities	**$ 1,127**	$ 2,323	**$ (2,134)**	$ 6,514
Add back				
Increase (decrease) in accounts receivable	**(128)**	(287)	**(23)**	(104)
(Increase) decrease in accounts payable and accrued expenses	**374**	(689)	**573**	(710)
Other items—net	**(1,069)**	198	**(800)**	225
Tronox settlement payment	**—**	—	**5,215**	—
Certain nonoperating and other excluded items	**1**	24	**26**	25
Current taxes related to asset monetizations and Tronox tax position	**674**	207	**990**	1,033
Discretionary cash flow from operations	**$ 979**	$ 1,776	**$ 3,847**	$ 6,983

	Quarter Ended September 30,		Nine Months Ended September 30,	
millions	**2015**	2014	**2015**	2014
Discretionary cash flow from operations	**$ 979**	$ 1,776	**$ 3,847**	$ 6,983
Less capital expenditures*	**1,352**	2,117	**4,575**	7,087
Free cash flow**	**$ (373)**	$ (341)	**$ (728)**	$ (104)

* Includes Western Gas Partners, LP (WES) capital expenditures of $127 million for the quarter ended September 30, 2015, $147 million for the quarter ended September 30, 2014, $405 million for the nine months ended September 30, 2015, and $490 million for the nine months ended September 30, 2014.

** Free cash flow for the nine months ended September 30, 2015, includes a $910 million current tax benefit associated with the Tronox settlement.

Presented below is a reconciliation of total debt (GAAP) to net debt (non-GAAP). Management uses net debt as a measure of the Company's outstanding debt obligations that would not be readily satisfied by its cash and cash equivalents on hand.

	September 30, 2015		
millions	**Anadarko Consolidated**	**WGP* Consolidated**	**Anadarko excluding WGP**
Total debt	**$ 15,925**	**$ 2,587**	**$ 13,338**
Less cash and cash equivalents	**2,072**	**75**	**1,997**
Net debt	**$ 13,853**	**$ 2,512**	**$ 11,341**

millions	**Anadarko Consolidated**	**Anadarko excluding WGP**
Net debt	**$ 13,853**	**$ 11,341**
Total equity	**17,052**	**14,079**
Adjusted capitalization	**$ 30,905**	**$ 25,420**
Net debt to adjusted capitalization ratio	**45%**	**45%**

* Western Gas Equity Partners, LP (WGP) is a publicly traded consolidated subsidiary of Anadarko and WES is a consolidated subsidiary of WGP.

Anadarko Petroleum Corporation
(Unaudited)

Summary Financial Information *millions except per-share amounts*	Quarter Ended September 30, 2015	Quarter Ended September 30, 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
Consolidated Statements of Income				
Revenues and Other				
Natural-gas sales	$ 484	$ 830	$ 1,612	$ 3,038
Oil and condensate sales	1,229	2,637	4,264	7,766
Natural-gas liquids sales	183	424	644	1,221
Gathering, processing, and marketing sales	334	339	932	928
Gains (losses) on divestitures and other, net	(542)	780	(807)	2,340
Total	1,688	5,010	6,645	15,293
Costs and Expenses				
Oil and gas operating	262	275	784	861
Oil and gas transportation and other	271	322	921	869
Exploration	1,074	199	2,260	1,000
Gathering, processing, and marketing	289	269	798	771
General and administrative	345	381	933	984
Depreciation, depletion, and amortization	1,111	1,163	3,581	3,335
Other taxes	127	306	460	981
Impairments	758	394	3,571	514
Deepwater Horizon settlement and related costs	—	3	4	96
Total	4,237	3,312	13,312	9,411
Operating Income (Loss)	(2,549)	1,698	(6,667)	5,882
Other (Income) Expense				
Interest expense	199	204	616	573
(Gains) losses on derivatives, net	282	(323)	123	453
Other (income) expense, net	47	24	109	12
Tronox-related contingent loss	—	19	5	4,338
Total	528	(76)	853	5,376
Income (Loss) Before Income Taxes	(3,077)	1,774	(7,520)	506
Income Tax Expense (Benefit)	(917)	627	(2,232)	1,719
Net Income (Loss)	(2,160)	1,147	(5,288)	(1,213)
Net Income (Loss) Attributable to Noncontrolling Interests	75	60	154	142
Net Income (Loss) Attributable to Common Stockholders	$ (2,235)	$ 1,087	$ (5,442)	$ (1,355)
Per Common Share				
Net income (loss) attributable to common stockholders—basic	$ (4.41)	$ 2.13	$ (10.73)	$ (2.69)
Net income (loss) attributable to common stockholders—diluted	$ (4.41)	$ 2.12	$ (10.73)	$ (2.69)
Average Number of Common Shares Outstanding—Basic	508	506	508	505
Average Number of Common Shares Outstanding—Diluted	508	508	508	505
Exploration Expense				
Dry hole expense	$ 817	$ 104	$ 859	$ 527
Impairments of unproved properties	136	30	1,134	216
Geological and geophysical expense	67	13	105	93
Exploration overhead and other	54	52	162	164
Total	$ 1,074	$ 199	$ 2,260	$ 1,000

Anadarko Petroleum Corporation
(Unaudited)

Summary Financial Information *millions*		Quarter Ended September 30, **2015**		2014		Nine Months Ended September 30, **2015**		2014
Cash Flows from Operating Activities								
Net income (loss)	$	**(2,160)**	$	1,147	$	**(5,288)**	$	(1,213)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities								
Depreciation, depletion, and amortization		**1,111**		1,163		**3,581**		3,335
Deferred income taxes		**(1,440)**		(398)		**(2,627)**		(210)
Dry hole expense and impairments of unproved properties		**953**		134		**1,993**		743
Impairments		**758**		394		**3,571**		514
(Gains) losses on divestitures, net		**578**		(726)		**1,003**		(2,194)
Total (gains) losses on derivatives, net		**281**		(324)		**123**		462
Operating portion of net cash received (paid) in settlement of derivative instruments		**79**		48		**251**		(138)
Other		**145**		87		**219**		195
Changes in assets and liabilities								
Deepwater Horizon settlement and related costs		**(1)**		1		**—**		93
Tronox-related contingent liability		**—**		19		**(5,210)**		4,338
(Increase) decrease in accounts receivable		**128**		287		**23**		104
Increase (decrease) in accounts payable and accrued expenses		**(374)**		689		**(573)**		710
Other items—net		**1,069**		(198)		**800**		(225)
Net Cash Provided by (Used in) Operating Activities	$	**1,127**	$	2,323	$	**(2,134)**	$	6,514
Capital Expenditures	$	**1,352**	$	2,117	$	**4,575**	$	7,087

millions		**September 30, 2015**		December 31, 2014
Condensed Balance Sheets				
Cash and cash equivalents	$	**2,072**	$	7,369
Accounts receivable, net of allowance		**2,469**		2,527
Other current assets		**646**		1,325
Net properties and equipment		**35,381**		41,589
Other assets		**2,271**		2,310
Goodwill and other intangible assets		**6,343**		6,569
Total Assets	$	**49,182**	$	61,689
Other current liabilities		**4,348**		4,934
Deepwater Horizon settlement and related costs		**90**		90
Tronox-related contingent liability		**—**		5,210
Long-term debt		**15,892**		15,092
Deferred income taxes		**6,090**		9,249
Other long-term liabilities		**5,710**		4,796
Stockholders' equity		**14,079**		19,725
Noncontrolling interests		**2,973**		2,593
Total Equity	$	**17,052**	$	22,318
Total Liabilities and Equity	$	**49,182**	$	61,689
Capitalization				
Total debt	$	**15,925**	$	15,092
Total equity		**17,052**		22,318
Total	$	**32,977**	$	37,410

Capitalization Ratios		
Total debt	**48%**	40%
Total equity	**52%**	60%

Anadarko Petroleum Corporation
(Unaudited)

Sales Volumes and Prices

	Average Daily Sales Volumes			Sales Volumes			Average Sales Price		
	Natural Gas MMcf/d	Oil & Condensate MBbls/d	NGLs MBbls/d	Natural Gas Bcf	Oil & Condensate MMBbls	NGLs MMBbls	Natural Gas Per Mcf	Oil & Condensate Per Bbl	NGLs Per Bbl
Quarter Ended September 30, 2015									
United States	**2,186**	**224**	**117**	**201**	**21**	**11**	**$ 2.41**	**$ 43.48**	**$ 15.83**
Algeria	**—**	**49**	**5**	**—**	**4**	**1**	**—**	**47.86**	**25.18**
Other International	**—**	**28**	**—**	**—**	**3**	**—**	**—**	**46.30**	**—**
Total	**2,186**	**301**	**122**	**201**	**28**	**12**	**$ 2.41**	**$ 44.45**	**$ 16.26**
Quarter Ended September 30, 2014									
United States	2,494	213	129	230	20	11	$ 3.62	$ 92.59	$ 35.11
Algeria	—	62	1	—	6	—	—	98.69	65.55
Other International	—	28	—	—	2	—	—	100.48	—
Total	2,494	303	130	230	28	11	$ 3.62	$ 94.56	$ 35.35
Nine Months Ended September 30, 2015									
United States	**2,424**	**233**	**128**	**662**	**64**	**35**	**$ 2.44**	**$ 47.37**	**$ 17.08**
Algeria	**—**	**56**	**6**	**—**	**15**	**2**	**—**	**54.90**	**29.79**
Other International	**—**	**28**	**—**	**—**	**8**	**—**	**—**	**52.58**	**—**
Total	**2,424**	**317**	**134**	**662**	**87**	**37**	**$ 2.44**	**$ 49.16**	**$ 17.63**
Nine Months Ended September 30, 2014									
United States	2,603	197	116	711	54	31	$ 4.27	$ 95.30	$ 38.21
Algeria	—	64	1	—	18	—	—	105.38	66.14
Other International	—	27	—	—	7	—	—	106.06	—
Total	2,603	288	117	711	79	31	$ 4.27	$ 98.57	$ 38.38

	Average Daily Sales Volumes MBOE/d	Sales Volumes MMBOE
Quarter Ended September 30, 2015	**787**	**73**
Quarter Ended September 30, 2014	849	78
Nine Months Ended September 30, 2015	**855**	**234**
Nine Months Ended September 30, 2014	839	229

Sales Revenue and Commodity Derivatives

	Sales			Net Cash Received (Paid) from Settlement of Commodity Derivatives		
millions	Natural Gas	Oil & Condensate	NGLs	Natural Gas	Oil & Condensate	NGLs
Quarter Ended September 30, 2015						
United States	**$ 484**	**$ 897**	**$ 170**	**$ 78**	**$ 1**	**$ —**
Algeria	**—**	**214**	**13**	**—**	**—**	**—**
Other International	**—**	**118**	**—**	**—**	**—**	**—**
Total	**$ 484**	**$ 1,229**	**$ 183**	**$ 78**	**$ 1**	**$ —**
Quarter Ended September 30, 2014						
United States	$ 830	$ 1,817	$ 418	$ 15	$ (8)	$ 1
Algeria	—	565	6	—	40	—
Other International	—	255	—	—	—	—

Total	$	830	$	2,637	$	424	$	15	$	32	$	1
Nine Months Ended September 30, 2015												
United States	**$**	**1,612**	**$**	**3,018**	**$**	**596**	**$**	**228**	**$**	**6**	**$**	**17**
Algeria		**—**		**843**		**48**		**—**		**—**		**—**
Other International		**—**		**403**		**—**		**—**		**—**		**—**
Total	**$**	**1,612**	**$**	**4,264**	**$**	**644**	**$**	**228**	**$**	**6**	**$**	**17**
Nine Months Ended September 30, 2014												
United States	$	3,038	$	5,125	$	1,208	$	(107)	$	(68)	$	3
Algeria		—		1,858		13		—		40		—
Other International		—		783		—		—		—		—
Total	$	3,038	$	7,766	$	1,221	$	(107)	$	(28)	$	3

Anadarko Petroleum Corporation
Financial and Operating External Guidance
As of October 27, 2015

Note: Guidance excludes 2015 sales volumes associated with EOR, Bossier, and Powder River Basin CBM.

	4th-Qtr Guidance (see Note)			Full-Year Guidance (see Note)		
	Units			Units		
Total Sales Volumes (MMBOE)	68	—	70	290	—	292
Total Sales Volumes (MBOE/d)	739	—	761	795	—	800
Oil (MBbl/d)	297	—	305	308	—	312
United States	218	—	222	226	—	228
Algeria	61	—	63	57	—	58
Ghana	18	—	20	25	—	26
Natural Gas (MMcf/d)						
United States	1,980	—	2,020	2,140	—	2,160
Natural Gas Liquids (MBbl/d)						
United States	106	—	111	122	—	124
Algeria	5	—	7	5	—	6
	$ / Unit			$ / Unit		
Price Differentials vs NYMEX (w/o hedges)						
Oil ($/Bbl)	(4.40)	—	(0.40)	(3.40)	—	(0.40)
United States	(6.00)	—	(2.00)	(5.00)	—	(2.00)
Algeria	—	—	4.00	1.00	—	4.00
Ghana	—	—	4.00	1.00	—	4.00
Natural Gas ($/Mcf)						
United States	(0.45)	—	(0.35)	(0.45)	—	(0.35)

Anadarko Petroleum Corporation
Financial and Operating External Guidance
As of October 27, 2015

Note: Guidance excludes items affecting comparability

	4th-Qtr Guidance (see Note)			Full-Year Guidance (see Note)		
	$ MM			$ MM		
Other Revenues						
Marketing and Gathering Margin	40	—	50	175	—	185
Minerals and Other	45	—	55	275	—	285
	$ / BOE			$ / BOE		
Costs and Expenses						
Oil & Gas Direct Operating	3.40	—	3.60	3.35	—	3.45
Oil & Gas Transportation/Other	3.75	—	3.95	3.70	—	3.80
Depreciation, Depletion, and Amortization	15.35	—	15.85	15.30	—	15.50
Production Taxes (% of Product Revenue)	7.5%	—	8.5%	7.0%	—	7.5%
	$ MM			$ MM		
General and Administrative	340	—	350	1,270	—	1,280
Exploration Expense						
Non-Cash	230	—	250	500	—	550
Cash	120	—	140	375	—	395
Interest Expense (net)	200	—	210	815	—	825
Other (Income) Expense	35	—	45	200	—	210
Taxes						
Algeria (All current)	55%	—	60%	55%	—	60%
Rest of Company (60% Current / 40% Deferred for Q4 and 25% Current / 75% deferred for FY)	35%	—	45%	30%	—	40%
Avg. Shares Outstanding (MM)						
Basic	507	—	508	507	—	509
Diluted	508	—	510	508	—	510
Capital Investment (Excluding Western Gas Partners, LP)	$ MM			$ MM		
APC Capital Expenditures	1,225	—	1,425	5,400	—	5,600

Anadarko Petroleum Corporation
Commodity Hedge Positions
As of October 27, 2015

	Volume (MBbls/d)	Weighted Average Price per barrel					
			Floor Sold		Floor Purchased		Ceiling Sold
Crude Oil							
Three-Way Collars							
2016							
WTI	65	$	41.54	$	53.08	$	62.25
Brent	18	$	47.22	$	59.44	$	69.47
	83	$	42.77	$	54.46	$	63.82

	Volume (thousand MMBtu/d)	Weighted Average Price per MMBtu					
			Floor Sold		Floor Purchased		Ceiling Sold
Natural Gas							
Three-Way Collars							
2015	635	$	2.75	$	3.75	$	4.76
Extendable Fixed Price - Financial							
2015*	170	$	4.17				

* Includes an option for the counterparty to extend the contract term to December 2016 at the same price.

Interest-Rate Derivatives

As of October 27, 2015

Instrument	Notional Amt.	Reference Period	Mandatory Termination Date	Rate Paid	Rate Received
Swap	$50 Million	Sept. 2016 - Sept. 2026	Sept. 2016	5.910%	3M LIBOR
Swap	$50 Million	Sept. 2016 - Sept. 2046	Sept. 2016	6.290%	3M LIBOR
Swap	$250 Million	Sept. 2016 - Sept. 2046	Sept. 2018	6.310%	3M LIBOR
Swap	$300 Million	Sept. 2016 - Sept. 2046	Sept. 2020	6.509%	3M LIBOR
Swap	$250 Million	Sept. 2016 - Sept. 2046	Sept. 2021	6.724%	3M LIBOR
Swap	$200 Million	Sept. 2017 - Sept. 2047	Sept. 2018	6.049%	3M LIBOR
Swap	$300 Million	Sept. 2017 - Sept. 2047	Sept. 2020	6.569%	3M LIBOR
Swap	$500 Million	Sept. 2017 - Sept. 2047	Sept. 2021	6.654%	3M LIBOR

Anadarko Petroleum Corporation
Reconciliation of Same-Store Sales

Average Daily Sales Volumes

	Quarter Ended September 30, 2015				Quarter Ended September 30, 2014			
	Natural Gas MMcf/d	Oil & Condensate MBbls/d	NGLs MBbls/d	Total MBOE/d	Natural Gas MMcf/d	Oil & Condensate MBbls/d	NGLs MBbls/d	Total MBOE/d
U.S. Onshore	**1,883**	**162**	**110**	**586**	2,049	146	124	611
Deepwater Gulf of Mexico	**158**	**55**	**7**	**88**	154	46	5	77
International and Alaska	**—**	**84**	**5**	**89**	—	98	1	99
Same-Store Sales	**2,041**	**301**	**122**	**763**	2,203	290	130	787
Divestitures*	**145**	**—**	**—**	**24**	291	13	—	62
Total	**2,186**	**301**	**122**	**787**	2,494	303	130	849

	Nine Months Ended September 30, 2015				Nine Months Ended September 30, 2014			
	Natural Gas MMcf/d	Crude Oil & Condensate MBbls/d	NGLs MBbls/d	Total MBOE/d	Natural Gas MMcf/d	Crude Oil & Condensate MBbls/d	NGLs MBbls/d	Total MBOE/d
U.S. Onshore	**2,037**	**168**	**121**	**629**	2,094	131	110	590
Deepwater Gulf of Mexico	**164**	**53**	**7**	**87**	201	44	6	84
International and Alaska	**—**	**92**	**6**	**98**	—	96	1	97
Same-Store Sales	**2,201**	**313**	**134**	**814**	2,295	271	117	771
Divestitures*	**223**	**4**	**—**	**41**	308	17	—	68
Total	**2,424**	**317**	**134**	**855**	2,603	288	117	839

* Includes China, Pinedale/Jonah, EOR, Bossier, and Powder River Basin CBM.

Average Daily Sales Volumes

	Year Ended December 31, 2014			
	Natural Gas MMcf/d	Crude Oil & Condensate MBbls/d	NGLs MBbls/d	Total MBOE/d
U.S. Onshore	2,092	136	111	595
Deepwater Gulf of Mexico	196	45	5	83
International and Alaska	—	94	3	97
Same-Store Sales	2,288	275	119	775
Divestitures*	301	17	—	68
Total	2,589	292	119	843

* Includes China, Pinedale/Jonah, EOR, Bossier, and Powder River Basin CBM.

Exhibit 98

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INVESTOR RELATIONS

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Third-Quarter 2015

OPERATIONS REPORT

October 27, 2015

3rd Quarter 2015 Highlights 2
Overview..3
U.S. Onshore....................................4
Rockies...5
Southern & Appalachia 8
Gulf of Mexico..................................11
International & Frontier........................14
Deepwater Rig Schedule 17
Glossary of Abbreviations.......................18

Exhibit
506

ANADARKO PETROLEUM CORPORATION

THIRD-QUARTER 2015 HIGHLIGHTS

ENHANCING MARGINS

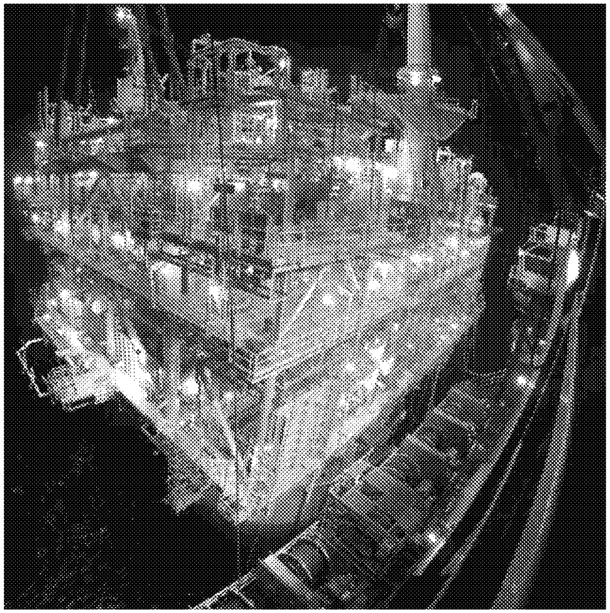
Anadarko delivered sales volumes of 72 MMBOE* during the 3rd quarter of 2015. Third-quarter sales volumes were reduced by approximately 900,000 BOE for the Powder River Basin CBM divestiture, which closed Sept. 1. The company remained focused on building and preserving value by growing higher-margin oil volumes by more than 42,000 BOPD year to date compared to the same period in 2014, while reducing costs.

U.S. oil sales volumes increased by approximately 24,000 BOPD compared to the 3rd quarter of 2014 and exceeded the high end of guidance. This was accomplished while the company continued to intentionally defer well completions in several U.S. onshore assets.

Both capital and direct operating expenses were below the low end of guidance during the quarter due to continued drilling, completion and operational efficiencies, process improvements and optimization.

ADVANCING HIGH-MARGIN MEGA PROJECTS

Subsequent to quarter end, Anadarko accomplished a major milestone by integrating the topsides of the Heidelberg spar with the hull in the deepwater Gulf of Mexico.



Installing topsides on Heidelberg spar, Gulf of Mexico

Offshore Ghana, the TEN development was more than 70% complete at the close of the quarter. The 80,000-BOPD project remains on schedule for first oil in mid-2016.

CREATING OPTION VALUE WITH EXPLORATION

During the quarter, Anadarko drilled a successful appraisal well at Shenandoah in the Gulf of Mexico. The well encountered more than 620 net feet of oil pay and continued to progress the giant oil discovery toward development.

Also in the Gulf of Mexico, an appraisal well at the Yeti discovery was spud to test multiple Miocene reservoirs in this prolific basin.

Offshore Colombia, Anadarko announced the play-opening discovery at Kronos and continued the exploration program at a second prospect, Calasu, which was spud during the 3rd quarter.

ACCELERATING VALUE THROUGH PORTFOLIO MANAGEMENT

Year to date, Anadarko is approaching $2 billion of monetizations. During the 3rd quarter, the company closed on the previously announced divestiture of its Bossier natural gas assets and related midstream infrastructure. Anadarko also closed the divestiture of its producing Powder River Basin CBM assets and signed a purchase and sale agreement for the divestiture of the associated gas gathering system.

**All volumes discussed in this report exclude production associated with China, EOR and Bossier to provide a "divestiture-adjusted" or "same-store" sales comparison. "Divestiture-adjusted" or "same-store" sales volumes are intended to present performance of Anadarko's continuing asset base, giving effect to recent divestitures.*

OVERVIEW

SALES VOLUMES

Third-quarter same-store sales volumes totaled 72 MMBOE, or 783,000 BOE/d, which was within guidance. Third-quarter sales volumes were reduced by approximately 900,000 BOE for the Powder River Basin CBM divestiture. U.S. oil volumes increased by approximately 12% from the 3rd quarter of 2014 primarily due to the performance of Wattenberg and the Gulf of Mexico.

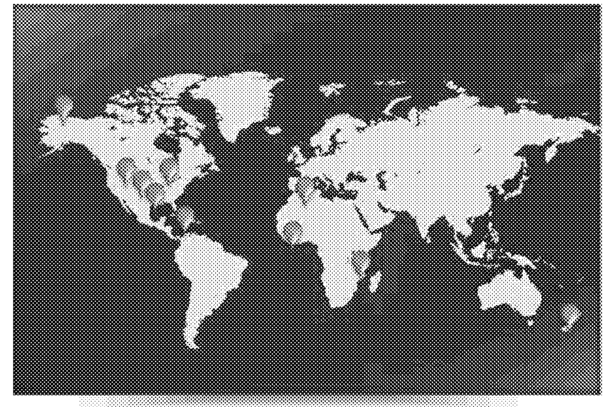
Anadarko has maintained flexibility in the U.S. onshore and intentionally deferred the completion of approximately 200 wells through the 3rd quarter. The company plans to exit 2015 with a range of 175 - 225 intentionally drilled, uncompleted wells (additional detail on page 4).

The company increased its full-year 2015 midpoint of divestiture-adjusted sales-volume guidance by 2 MMBOE to a range of 290 to 292 MMBOE, reflecting the monetization of the Powder River Basin CBM producing asset.

CAPITAL INVESTMENTS

Anadarko bolstered its cost structure through continued operational efficiencies and lower service costs. Third-quarter capital investments of $1.23 billion were below the low end of the guidance range of $1.25 - $1.45 billion, excluding WES capital investments.

For the second time this year, the company reduced the high end of its full-year capital guidance by $100 million, to a range of $5.4 - $5.6 billion, excluding WES capital investments.



SALES VOLUMES

	3Q15 Oil MBOPD	3Q15 NGLs MBbl/d	3Q15 Gas MMcf/d	3Q15 MMBOE	3Q14 Oil MBOPD	3Q14 NGLs MBbl/d	3Q14 Gas MMcf/d	3Q14 MMBOE
Rockies	103	57	1,093	31	93	69	1,202	33
Southern & Appalachia	59	53	911	24	53	55	1,063	27
Lower 48	**162**	**110**	**2,004**	**55**	**146**	**124**	**2,265**	**60**
Alaska	7	-	-	1	8	-	-	1
Gulf of Mexico	55	7	158	8	46	5	154	7
Total U.S.	**224**	**117**	**2,162**	**64**	**200**	**129**	**2,419**	**68**
*International**	77	5	-	8	90	1	-	8
Same-Store Sales	**301**	**122**	**2,162**	**72**	**290**	**130**	**2,419**	**76**
*EOR & Bossier***	-	-	24	1	13	-	75	2
Total Company	**301**	**122**	**2,186**	**73**	**303**	**130**	**2,494**	**78**

*Quarterly sales volumes are influenced by size, timing and scheduling of tanker liftings.
**The EOR divestiture closed in 2Q15, and the Bossier divestiture closed in 3Q15.

CAPITAL INVESTMENTS

	3Q15 $MM
Rockies	354
Southern & Appalachia	395
Lower 48	**749**
Alaska	26
Gulf of Mexico	146
Total U.S.	**921**
International	234
*Midstream****	144
Capitalized Items/Other	53
Total Company	**1,352**

*** Includes WES capital investments of ~$127 million

PROVIDING FLEXIBILITY WITH THE U.S. ONSHORE

EFFICIENCIES AND COST SAVINGS ENHANCE VALUE

Anadarko's U.S. onshore assets continued to deliver more for less through additional cost savings and enhanced efficiencies in the company's primary operating areas.

The U.S. onshore oil sales volumes increased by nearly 16,000 BOPD compared to 3rd quarter 2014, adjusted for divestitures. This 11% growth of Anadarko's higher-margin oil volumes was driven by performance from Wattenberg, Eagleford and the Delaware Basin.

Anadarko continued to leverage its integrated midstream advantage to enhance well margins and moderate the base decline. While the company continued to expand the Delaware Basin infrastructure in West Texas during the quarter, downtime was reduced by more than 18% compared to the 2nd quarter of 2015. U.S. onshore LOE per BOE has improved by 20% from the annual 2014 average due to operational efficiencies and cost savings.

Across the U.S. onshore, the company operated an average of 23 rigs during the quarter, a decrease of 20 rigs (47%) compared to the average rig count in 2014. The company also reduced completions activity by 47% to 8 crews during the quarter from an average of 15 in 2014.

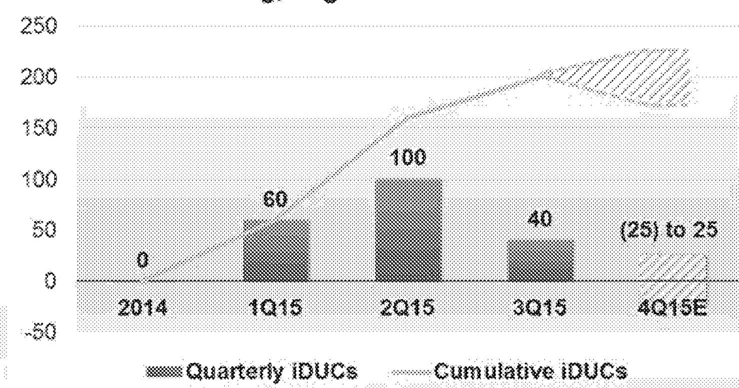
Anadarko reduced drilling cycle times in Wattenberg by approximately 20% and cost per foot by 15% over the previous quarter. Drilling times in the Eagleford have improved by 8% year to date, compared to 2014, which has enabled the company to shift rigs out of the asset while still drilling the same number of planned wellbores. Year to date, Anadarko has reduced Wolfcamp Shale well costs by nearly 40% per well, primarily due to efficiency gains as the company continues to learn and optimize operations in this emerging oil play.

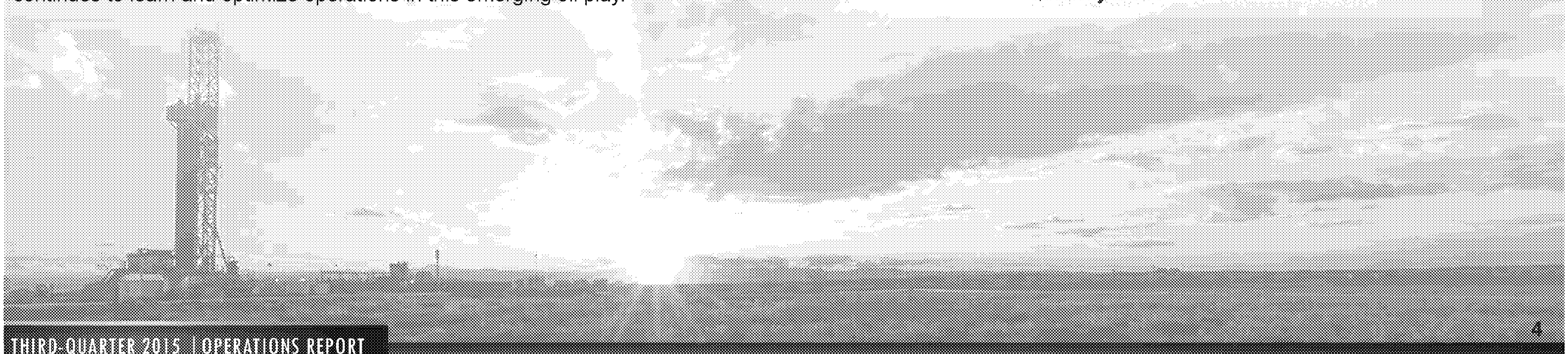
INTENTIONALLY DEFERRED COMPLETIONS ENHANCE VALUE

Anadarko continued to focus on preserving value by decreasing capital investments on short-cycle activities in the current lower commodity-price environment. As part of this approach, the company has systematically built a year-to-date inventory, of approximately 200 intentionally deferred completions, which has enabled Anadarko to continue realizing drilling efficiencies and significant cost savings resulting in enhanced returns in each of its major U.S. onshore focus areas.

The cost improvements achieved year to date, including a more than 30% reduction in completion costs, have enhanced the well returns in these assets and provides the opportunity to add completion crews to improve production flexibility into 2016.

Intentionally Deferred Completions in Wattenberg, Eagleford and Delaware Basin





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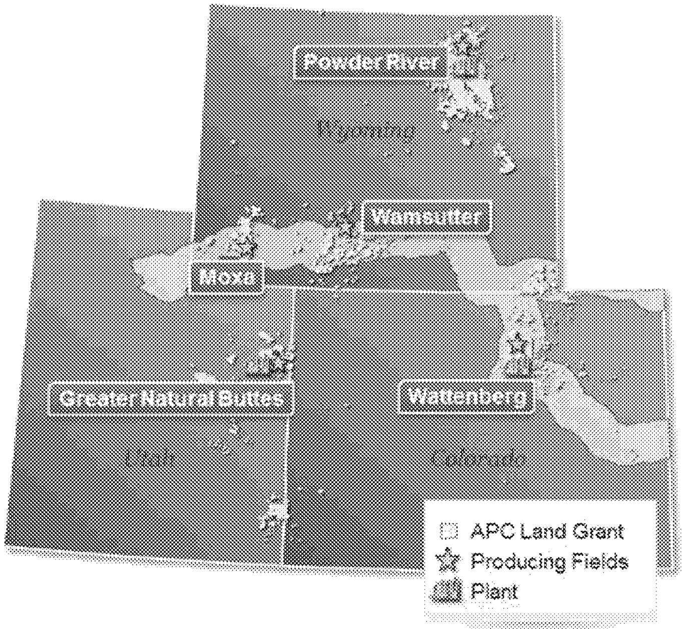
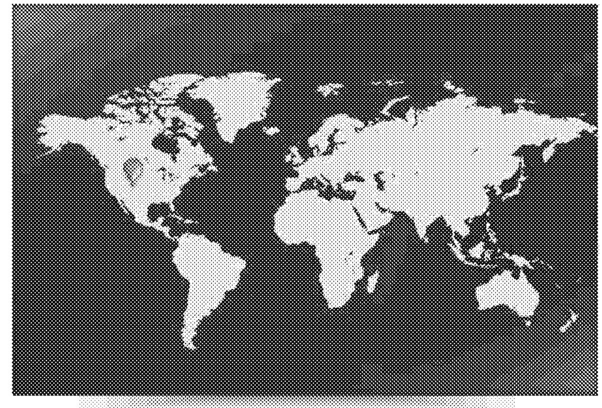
ROCKIES



Anadarko's Rockies assets delivered sales volumes averaging 342,000 BOE/d during the 3rd quarter, a 6% decrease over the same period in 2014, adjusted for divestitures. The decrease was largely the result of the company's decision to build an inventory of intentionally drilled, uncompleted wells in Wattenberg and reject ethane until margins improve. Higher-margin oil volumes increased 10% versus the 3rd quarter of 2014. The company continued to make the economic decision to reject ethane, which equated to a net sales volumes reduction of 1.6 MMBOE.

Anadarko averaged eight operated rigs and drilled 140 wells in the 3rd quarter with the majority of the activity taking place in the liquids-rich Wattenberg field. This denotes a more than 100% drilling-efficiency improvement versus 3rd quarter of 2014 when Anadarko drilled 122 wells with 14 operated rigs in the region.



SALES VOLUMES

	3Q15 Oil MBOPD	3Q15 NGLs MBbl/d	3Q15 Gas MMcf/d	3Q15 MBOE/d	3Q14 Oil MBOPD	3Q14 NGLs MBbl/d	3Q14 Gas MMcf/d	3Q14 MBOE/d
Wattenberg	94	44	493	220	82	50	340	189
Greater Natural Buttes	2	9	290	59	3	14	429	88
*Powder River Basin**	1	-	124	22	3	-	221	40
Wamsutter	2	5	98	24	2	7	105	27
Other	4	(1)	88	17	3	(2)	107	18
Same-Store Sales	**103**	**57**	**1,093**	**342**	**93**	**69**	**1,202**	**362**
*EOR***	-	-	-	-	13	-	-	13
Total	**103**	**57**	**1,093**	**342**	**106**	**69**	**1,202**	**375**

*The CBM divestiture announced in 3Q15 was included in 3Q15 sales volumes guidance and is included here in actuals.
**The EOR divestiture closed in 2Q15.

	CAPITAL INVESTMENTS 3Q15 $MM	AVERAGE RIG ACTIVITY 3Q15 Operated	AVERAGE RIG ACTIVITY 2Q15 Operated
Wattenberg	282	6	8
Greater Natural Buttes	21	1	1
*Powder River Basin**	6	1	-
Wamsutter	-	-	-
EOR	-	-	-
Other	45	-	-
Total	**354**	**8**	**9**

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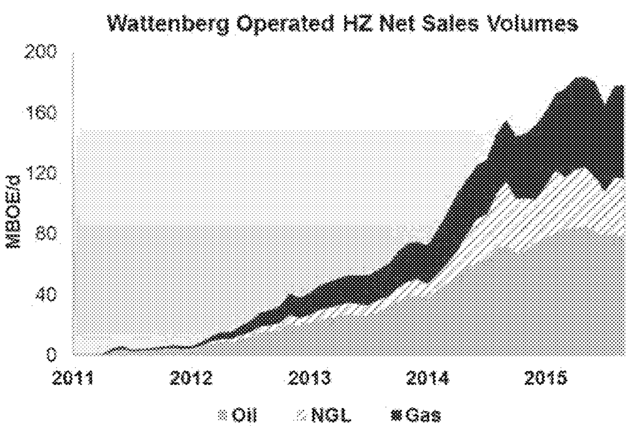
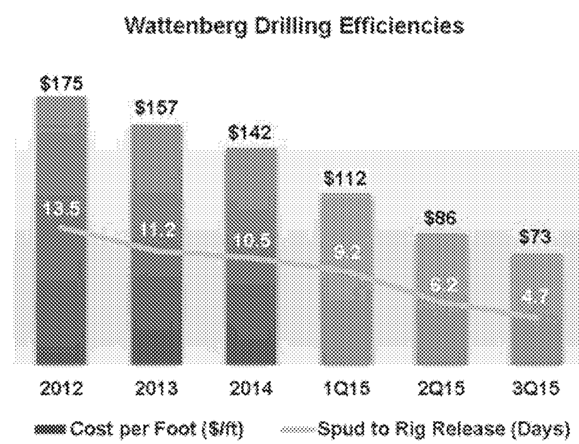
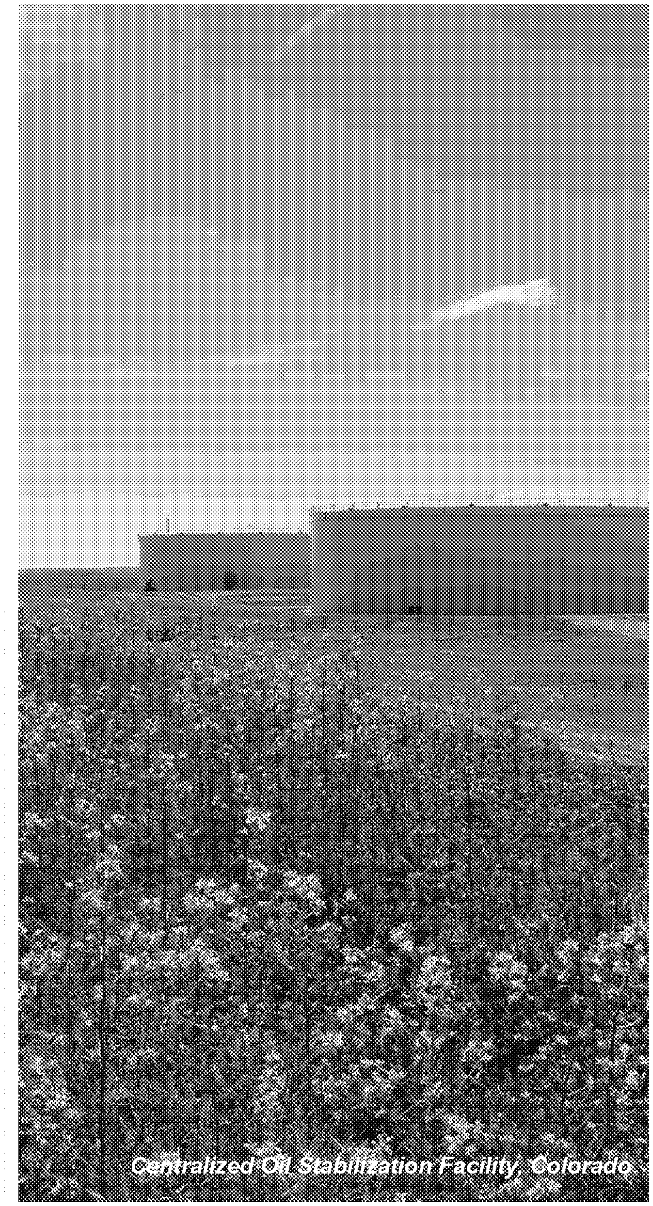
Wattenberg:

- During the 3rd quarter, the Wattenberg field net sales volumes decreased approximately 12,000 BOE/d or 5% compared with the 2nd quarter of 2015 to an average of approximately 220,000 BOE/d. The decrease was primarily due to the decision to defer 120 completions year-to-date as a result of reducing completion crews. Oil sales volumes increased 14% year over year.



- Anadarko operated an average of six rigs and drilled 105 wells (117 type-well equivalents) during the 3rd quarter and entered the 4th quarter with five rigs.
- The company averaged a record $73 per foot drilling cost during the 3rd quarter attributed to continued wellbore-design optimization and efficiency gains.
- Anadarko improved LOE by more than 30% in the 3rd quarter of 2015 to $1.68 per BOE, compared to the 2014 average of $2.40 per BOE.
- Phase II of the Lancaster cryogenic gas plant ramped up during the quarter. The 300-MMcf/d expansion doubles Anadarko's processing capacity at the Lancaster complex to 600 MMcf/d.
- The Lancaster I plant experienced downtime in September and October. Sales volumes were minimally impacted due to the company's integrated gathering system which enabled gas volumes to be diverted to and processed at the Lancaster II, Fort Lupton and Wattenberg plants.
- Construction was almost 85% complete at the centralized oil stabilization facility at the end of the 3rd quarter. Commissioning and startup are expected to occur in the 4th quarter of 2015. This facility will increase oil recoveries, enhance efficiencies of tank batteries, lower operating expenses and improve environmental performance.





Centralized Oil Stabilization Facility, Colorado

Greater Natural Buttes:

- The company operated one rig and drilled 16 wells in the 3rd quarter. Net natural gas sales volumes averaged 290 MMcf/d for the quarter.
- Anadarko has reduced drilling costs by 15% and completion costs by 22% year to date.

Laramie County, Wyoming:

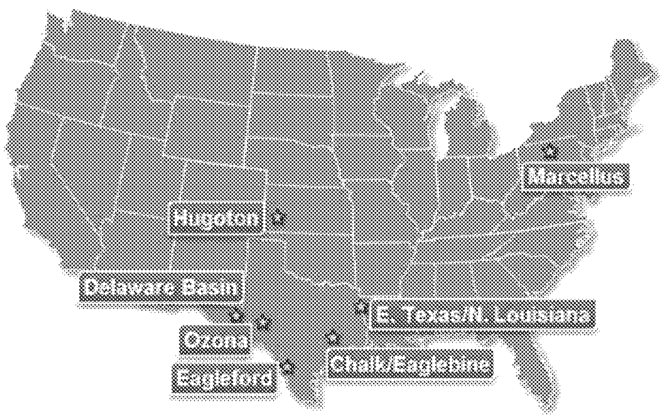
- Anadarko participated in seven non-operated well completions in the emerging liquids-rich play during the 3rd quarter.

Powder River Basin Oil:

- During the 3rd quarter, the company initiated a three-well exploration program targeting the Turner formation.

Greater Natural Buttes, Utah

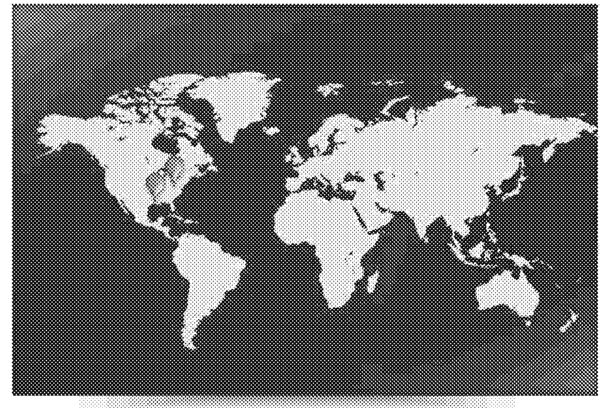
SOUTHERN & APPALACHIA



During the 3rd quarter, the Southern & Appalachia region delivered same-store sales volumes of more than 263,000 BOE/d, a 4% decrease from the 2nd quarter of 2015. The decrease was largely the result of the company's decision to build an inventory of intentionally drilled, uncompleted wells in the Eagleford Shale.

Oil volumes grew more than 11% year over year driven by continued development in the Eagleford and Wolfcamp Shale delineation activities in the Delaware Basin.

The company continued to achieve further efficiency gains and set new drilling records in each active area within the region during the 3rd quarter.



SALES VOLUMES

	3Q15 Oil MBOPD	3Q15 NGLs MBbl/d	3Q15 Gas MMcf/d	3Q15 MBOE/d	3Q14 Oil MBOPD	3Q14 NGLs MBbl/d	3Q14 Gas MMcf/d	3Q14 MBOE/d
Eagleford	32	25	156	83	29	25	134	76
Delaware Basin	17	7	63	34	13	6	52	28
E. Texas/N. Louisiana	2	15	220	53	3	19	252	63
Chalk/Eaglebine	7	2	20	13	7	3	21	13
Marcellus	-	-	396	66	-	-	534	89
Hugoton	-	2	31	7	-	2	36	8
Ozona	-	2	21	6	-	2	23	6
Other	1	-	4	2	1	(2)	11	3
Same-Store Sales	**59**	**53**	**911**	**263**	**53**	**55**	**1,063**	**286**
*Bossier**	-	-	24	4	-	-	75	12
Total	**59**	**53**	**935**	**267**	**53**	**55**	**1,138**	**298**

**The Bossier divestiture closed in 3Q15.*

	CAPITAL INVESTMENTS 3Q15 $MM	AVERAGE RIG ACTIVITY 3Q15 Operated	AVERAGE RIG ACTIVITY 2Q15 Operated
Eagleford	89	3	5
Delaware Basin	225	7	7
E. Texas/N. Louisiana	56	4	4
Chalk/Eaglebine	9	1	1
Marcellus	9	-	-
*Bossier**	-	-	-
Hugoton	1	-	-
Ozona	1	-	-
Other	5	-	-
Total	**395**	**15**	**17**

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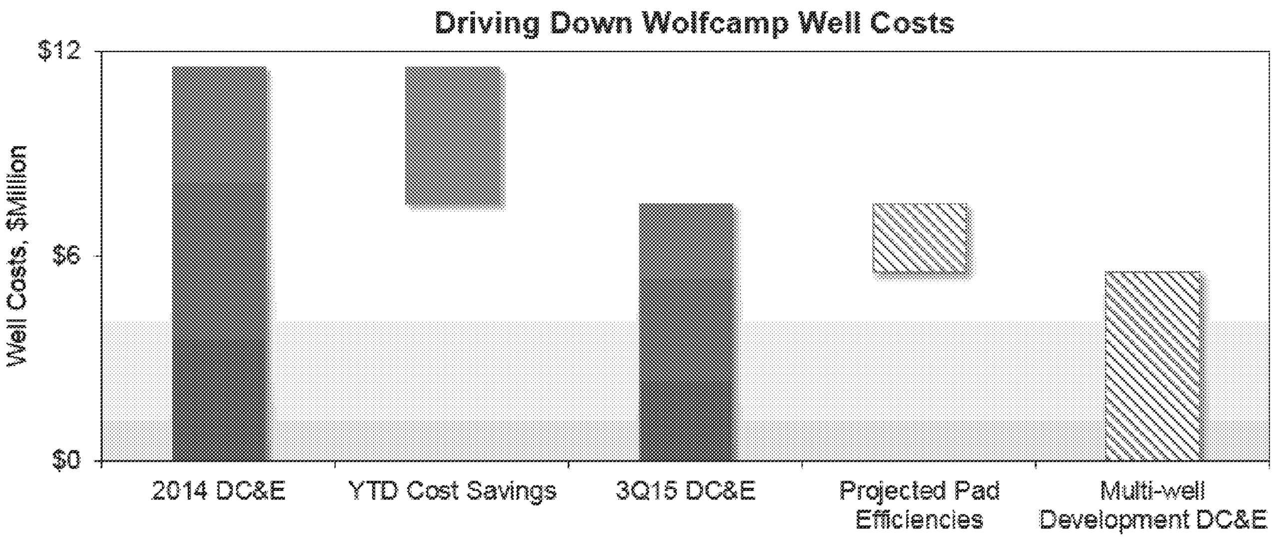
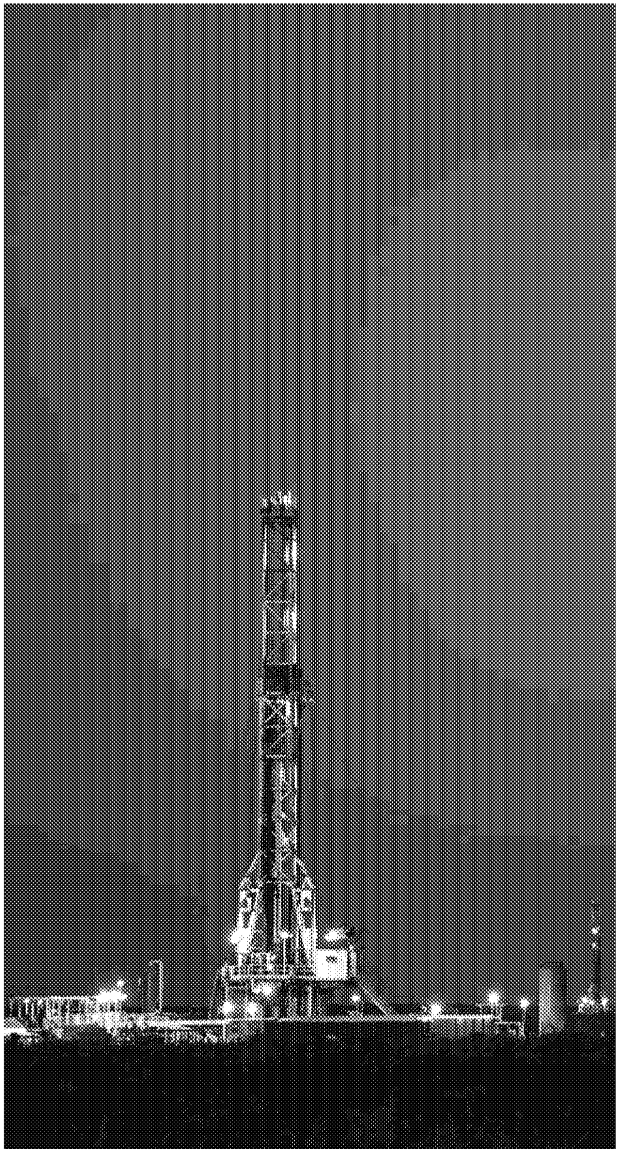
SOUTHERN & APPALACHIA

Delaware Basin:

- Anadarko's net sales volumes for the quarter averaged more than 34,000 BOE/d, an increase of 23% from the 3rd quarter of 2014. Total liquids volumes averaged nearly 24,000 Bbl/d, which is an increase of 24% compared to 2014.
- The company averaged seven operated rigs, spud 22 wells and brought 11 Wolfcamp Shale operated wells on line during the 3rd quarter.
- Anadarko also drilled and completed its first well in the 2nd Bone Spring during the quarter, which tested in excess of 1,000 BOPD.
- Anadarko continues to replicate the Wattenberg infrastructure model by integrating and expanding gathering and processing infrastructure for long-term growth and operational flexibility.
- During the quarter, Anadarko acquired approximately 3,000 acres of leasehold on the border of Reeves and Loving counties, which fills in a portion of Anadarko's existing checkerboard acreage.
- Anadarko continued to optimize the well construction process and set company milestones for longest lateral length, shortest drilling and completion times, and fastest rig mobilization during the quarter.
- The drilling team enhanced efficiencies and achieved a new quarterly record average of less than 24 days spud to rig release, a reduction of 15% from 3rd quarter of 2014.
- The completions team also experienced significant efficiency improvements, reducing time per completion stage by 38% from 2014.
- At the end of the 3rd quarter, well costs for 4,500-foot laterals were approximately $7.5 million with line of sight to below $6 million when the company elects to transition to pad development.





Delaware Basin, Texas

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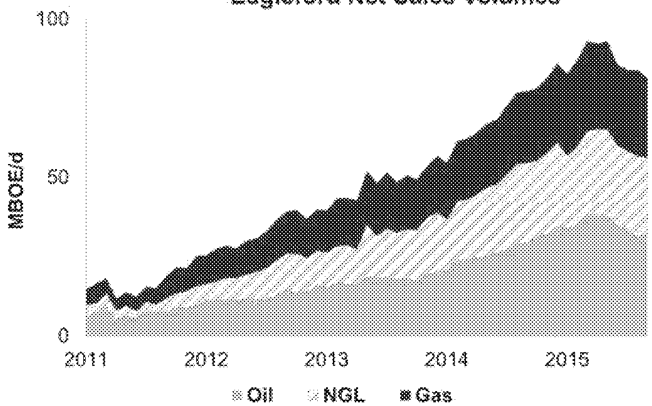
Eagleford:

- Anadarko's net sales volumes averaged 83,000 BOE/d during the quarter, an 8% decrease from the 2nd quarter of 2015. The decrease was primarily due to the decision to defer 40 completions year to date. Oil volumes averaged more than 32,000 BOPD, a 13% year-over-year increase.



- Anadarko spud 34 wells utilizing three operated rigs in the 3rd quarter.
- The company achieved a record low average cost per foot of $81, while averaging a record lateral length of more than 8,800 feet during the quarter.

East Texas/North Louisiana:

- Anadarko's net sales volumes averaged more than 53,000 BOE/d during the 3rd quarter, which was a decrease of 11% compared to the 2nd quarter of 2015.
- The company averaged four operated rigs, spud 11 wells and brought nine wells on line during the quarter.

Eaglebine:

- Anadarko's net sales volumes averaged more than 3,000 BOE/d during the 3rd quarter with the addition of five new wells, an increase of 7% compared to the 3rd quarter of 2014.
- During the 3rd quarter, the company reduced average drilling cost per foot by nearly 10% to a record low of $124 per foot from the 2nd quarter of 2015, while increasing the average lateral length by more than 20%. Since 2014, drilling cost per foot has improved approximately 30%.

Marcellus:

- Anadarko's net sales volumes averaged approximately 396 MMcf/d during the 3rd quarter and were impacted by voluntary curtailments.

Eagleford, Texas

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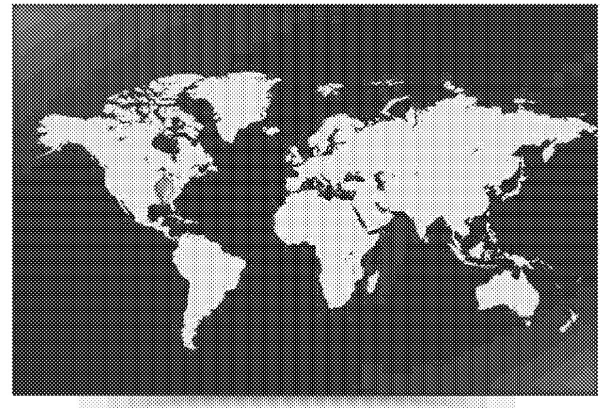
GULF OF MEXICO



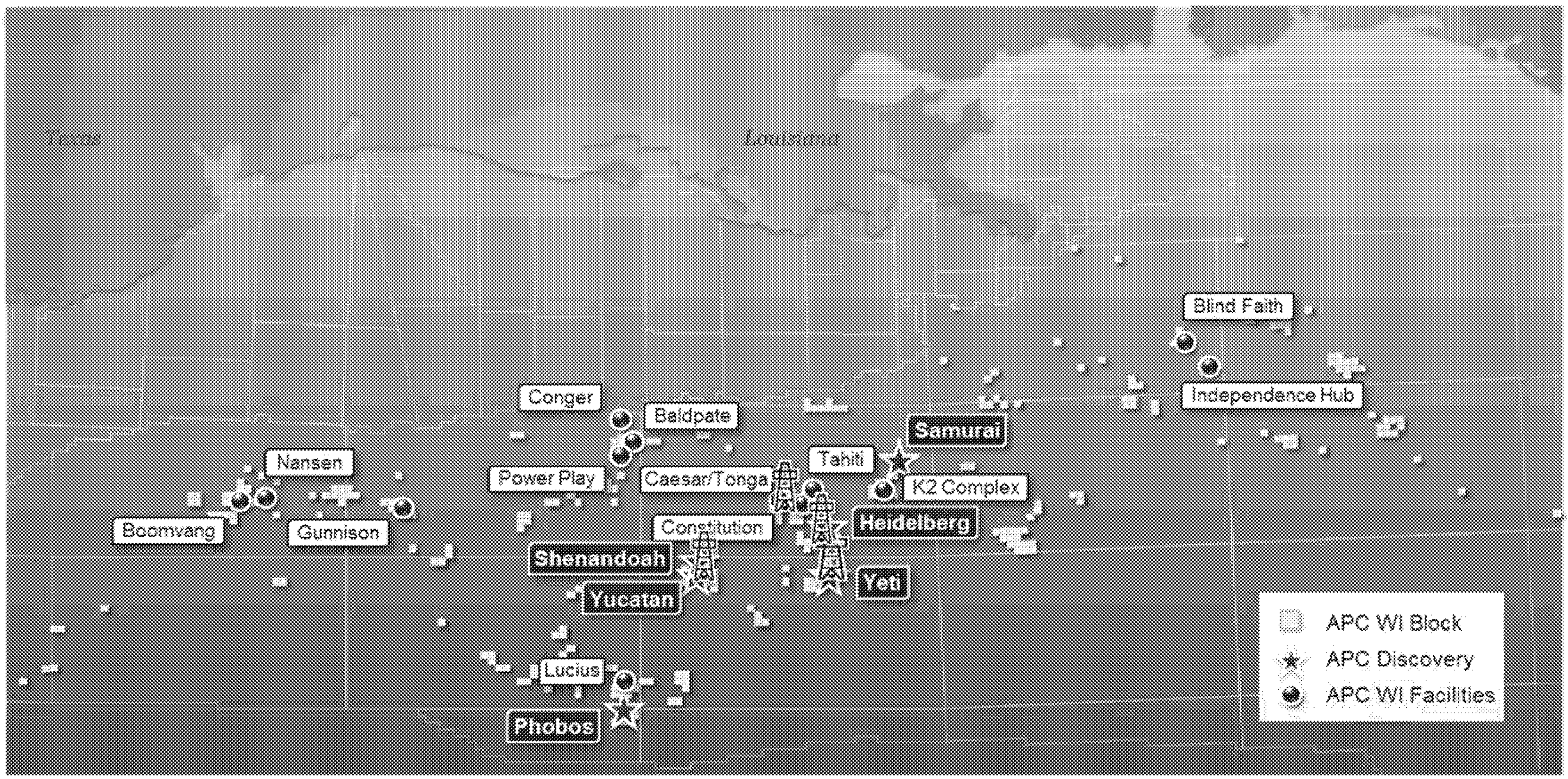
During the 3rd quarter, Anadarko's Gulf of Mexico region averaged sales volumes of approximately 88,000 BOE/d, up 14% from the same period in 2014.

Oil volumes increased compared to the 3rd quarter of 2014 due to strong performance at Lucius.

SALES VOLUMES*

	3Q15 Oil MBOPD	3Q15 NGLs MBbl/d	3Q15 Gas MMcf/d	3Q15 MBOE/d	3Q14 Oil MBOPD	3Q14 NGLs MBbl/d	3Q14 Gas MMcf/d	3Q14 MBOE/d
Total	55	7	158	88	46	5	154	77

Includes the impact of weather-related downtime.



Heidelberg, Gulf of Mexico

DEVELOPMENT

Heidelberg:

GREEN CANYON 859/860/903/904/948 (APC WI 31.5%)

- First oil has been accelerated and is now anticipated in the 2nd quarter of 2016 from the first three subsea wells, with production from two additional wells coming on line at a later date.
- Anadarko completed the umbilical and jumper installations for the spar during the 3rd quarter.
- The topsides set sail from Ingleside in late September and were successfully integrated onto the hull subsequent to quarter end.

Constitution/Ticonderoga:

- The A-4 well was completed and flow tested to more than 4,000 BOPD during the 3rd quarter.

Caesar/Tonga:

GREEN CANYON 683/726/727/770 (APC WI 33.75%)

- A sixth Caesar/Tonga well was drilled during the 3rd quarter and encountered approximately 191 net feet of oil pay. The well is expected to be completed and on line by 2016.
- A seventh well was being drilled at the end of the 3rd quarter and is also expected to be completed by year end and on line in early 2016.

K2 Complex:

- Anadarko completed a successful flow test of the Green Canyon 562 #5 well during the 3rd quarter with positive results for rate and drawdown. The company expects to increase production to a target rate of 7,000 BOPD during the 4th quarter.

Independence Hub:

- Gross production averaged 82 MMcf/d (78 MMcf/d net) during the quarter, an increase of more than 60% from the 2nd quarter of 2015.
- Anadarko re-established production at Jubilee 2 by shifting an upper sleeve in the wellbore, increasing production by 45 MMcf/d sequentially.

EXPLORATION/APPRAISAL

Shenandoah Basin:

WALKER RIDGE 51/52/53 (APC WI 30%, OPERATOR)

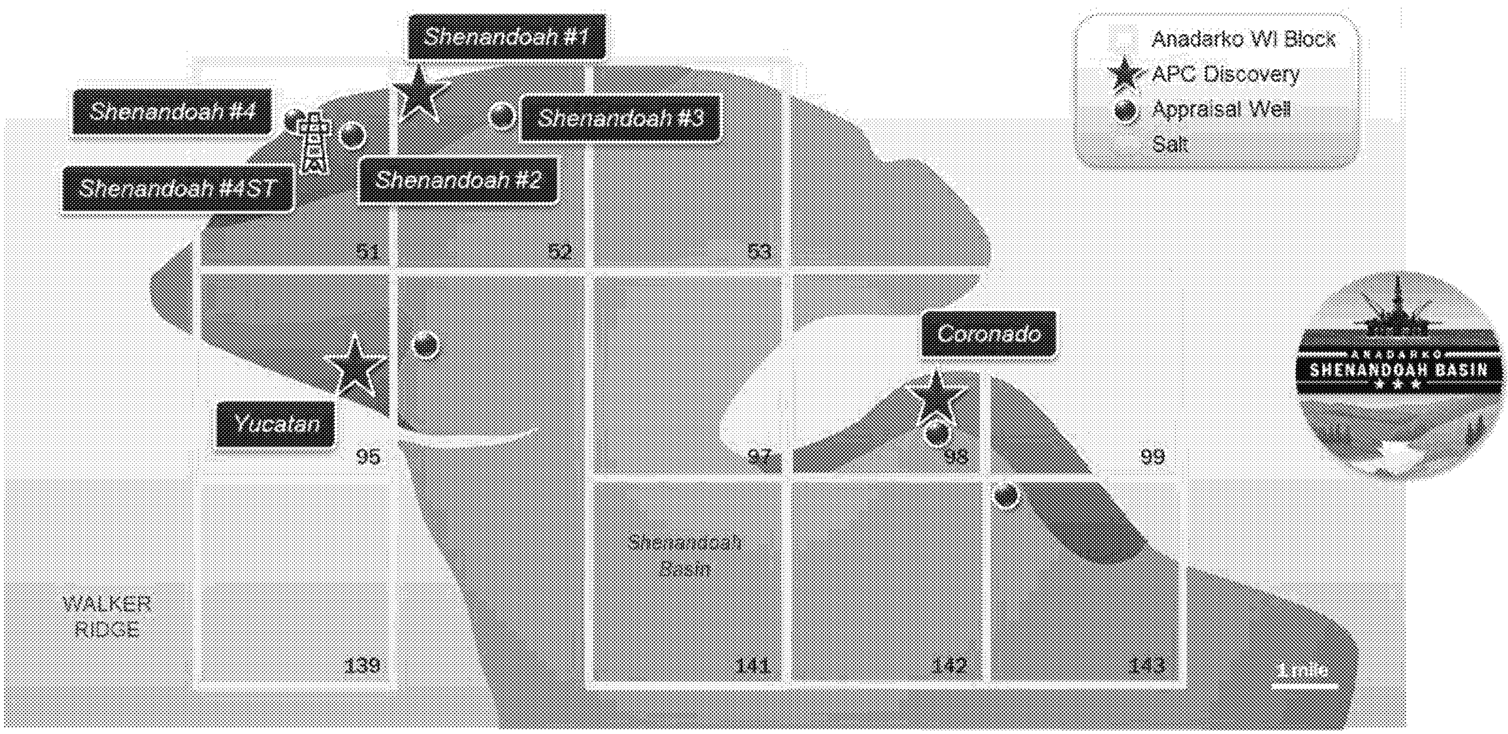
- During the quarter, the Shenandoah-4 appraisal well tested the up-dip extent of the basin. The subsequent Shenandoah-4 sidetrack encountered more than 620 net feet of oil pay, extending the lowest known oil column downdip. Operations continued after quarter close, with the partnership preparing to obtain whole-core across the reservoir interval.

Yeti:

WALKER RIDGE 117/157/158/159/160 (APC WI 37.5%)

- The Yeti-3 appraisal well spud in the 3rd quarter and is currently drilling. The Yeti-1 discovery well encountered more than 270 net feet of oil pay in Miocene-aged reservoirs, and the appraisal well is located about 2 miles southeast in approximately 5,900 feet of water. The well is designed to test additional exploration objectives not penetrated in the original discovery, as well as a down-dip appraisal of the Miocene-aged reservoirs encountered in Yeti-1.

Shenandoah Basin Leasehold



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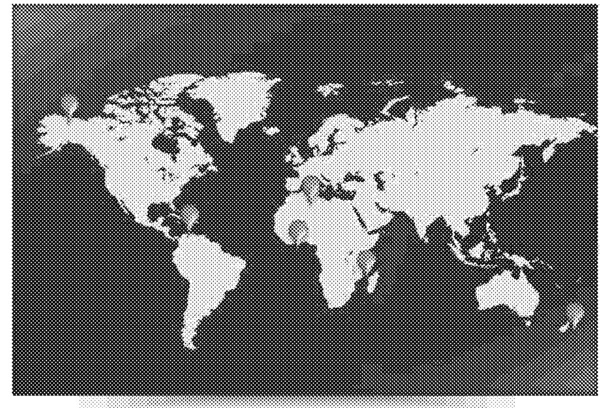
INTERNATIONAL & FRONTIER

El Merk, Algeria

During the 3rd quarter, the International and Frontier region sales volumes averaged 89,000 Bbl/d.

Oil sales volumes were below guidance because of a weather-related tanker lifting delay in Algeria.



SALES VOLUMES

	3Q15 MBbl/d	3Q14 MBbl/d
Alaska	7	8
*Algeria**	54	63
Brazil	-	-
*Ghana/W. Africa**	28	28
Mozambique	-	-
Other	-	-
Total	**89**	**99**

**Quarterly sales volumes are influenced by size, timing and scheduling of tanker liftings.*

CAPITAL INVESTMENTS

	3Q15 $MM
Alaska	26
Algeria	19
Brazil	-
Ghana/W. Africa	143
Mozambique	28
Other	44
Total	**260**

Jubilee FPSO, Ghana

DEVELOPMENT

Alaska:

- Gross production from the Colville River Unit averaged more than 42,000 BOPD during the quarter. Construction on the Alpine West satellite extension continues and drilling is under way. Initial production is expected by year end.

Algeria:

- Gross production averaged approximately 372,000 BOE/d from HBNS, Ourhoud and El Merk facilities during the quarter, which was a sequential increase of 17,000 BOE/d following completion of scheduled maintenance that took place at HBNS during the 2nd quarter of 2015.

Ghana:

- Gross production at the Jubilee field averaged approximately 93,000 BOPD during the quarter. This was 14,000 BOPD lower than the previous quarter due to curtailed production. This was due to a technical issue with the gas compression system from the beginning of July until the issue was resolved in early August. Gross production rates were above 100,000 BOPD at the end of the 3rd quarter.

- The TEN development was more than 70% complete at the close of the quarter. The third well was completed during the quarter and the remaining seven wells are scheduled for completion before startup. The 80,000-BOPD project remains on schedule for first oil in mid-2016.

Mozambique LNG:

OFFSHORE AREA 1 (APC WI 26.5%, OPERATOR)

- The partnership continues to work with the government to make progress on the remaining agreements and approvals that are required to support investment.

- The Area 1 participants continue to make preparations to select the offshore EPCI contractor and submit the Development Plan to the government.

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EXPLORATION/APPRAISAL

Colombia:

FUERTE NORTE, FUERTE SUR, PURPLE ANGEL, COL 5 AND URA 4 (APC WI 50%, OPERATOR)

- The Kronos-1 discovery encountered 130 - 230 net feet of natural gas pay in the upper objective, proving the presence of a working petroleum system and validating the geologic and seismic interpretations. The well finished drilling during the quarter, testing a deeper objective where it encountered non-commercial hydrocarbons. Anadarko and its partner are evaluating the drilling results to determine the next steps.
- The Calasu-1 well was spud in the 3rd quarter and is currently drilling a large four-way structure on the north end of the block complex with multiple potential targets.

BLOCKS COL 1, COL 2, COL 6 AND COL 7 (APC WI 100%, OPERATOR)

- Phase I of the Esmeralda 3D survey was more than 80% complete at the end of the 3rd quarter. The acquisition, which is approximately 16,000 km², is anticipated to be completed in the 4th quarter of 2015.

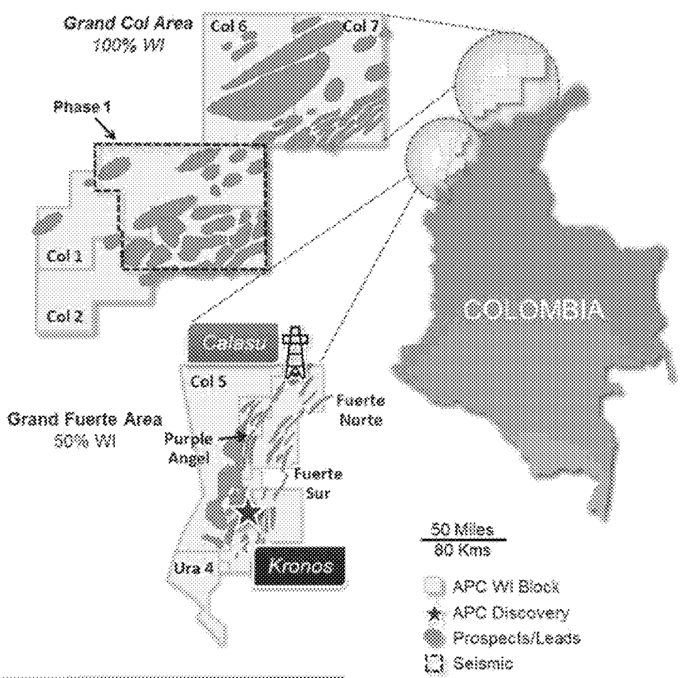
Côte d'Ivoire:

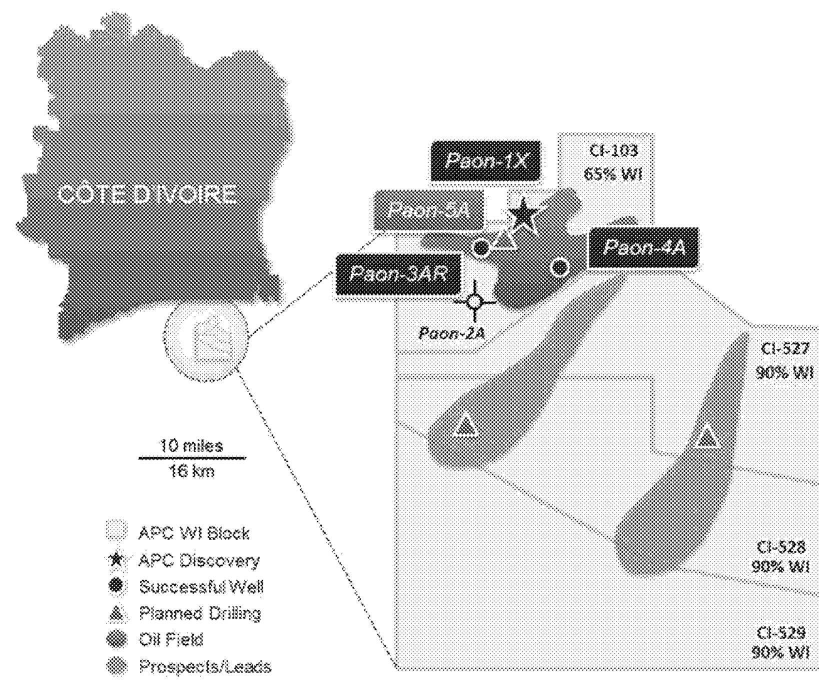
BLOCK CI-103 (APC WI 65%, OPERATOR)

- A drillstem test and interference testing program is expected to begin late in the 4th quarter as part of the continuing appraisal of the Paon discovery. The program will also include additional appraisal drilling. The data from these operations is expected to provide insight on reservoir connectivity, deliverability, fluid properties and reservoir size. Positive results will advance the discovery toward commerciality.

BLOCK CI-527/528/529 (APC WI 90%, OPERATOR)

- During the quarter, Anadarko acquired the CI-527 block, which adjoins and is contiguous with the CI-103 block to the northwest and the CI-528 block to the south. Planning is under way for a two-well exploration program in 2016.





DEEPWATER RIG SCHEDULE

	2015	2016	2017	2018	2019	2020
Noble Bob Douglas						
Rowan Resolute						
Bolette Dolphin						
Ocean BlackHawk						
Ocean BlackHornet						

Ocean BlackHornet Drillship

Bolette Dolphin Drillship

GLOSSARY OF ABBREVIATIONS

- **APC:** Anadarko Petroleum Corporation
- **Bbl/d:** Barrels of Liquids per Day
- **BOE:** Barrels of Oil Equivalent
- **BOE/d:** Barrels of Oil Equivalent per Day
- **BOP:** Blow Out Preventer
- **BOPD:** Barrels of Oil per Day
- **CBM:** Coal Bed Methane
- **DC&E:** Drill, Complete and Equip Cost
- **EOR:** Enhanced Oil Recovery
- **EPCI:** Engineering, Procurement Construction and Installation
- **FPSO:** Floating, Production, Storage and Offloading Unit
- **HBNS:** Hassi Berkine Sud (South)
- **HZ:** Horizontal
- **iDUC:** Intentionally Drilled, Uncompleted Wellbore
- **Km:** Kilometer
- **LNG:** Liquefied Natural Gas
- **LOE:** Lease Operating Expense
- **MBbl/d:** Thousand Barrels of Liquids per Day
- **MBOE/d:** Thousand Barrels of Oil Equivalent per Day
- **MBOPD:** Thousand Barrels of Oil per Day
- **MM:** Million
- **MMBOE:** Million Barrels of Oil Equivalent
- **MMcf/d:** Million Cubic Feet per Day
- **NGL:** Natural Gas Liquid
- **TEN:** Tweneboa, Enyenra and Ntomme
- **WES:** Western Gas Partners, LP (NYSE: WES)
- **WI:** Working Interest

Exhibit 99

Anadarko Petroleum Corporation
3Q15 Earnings Conference Call
Wednesday, October 28, 2015

Management
John Colglazier, SVP, IR and Communications
Al Walker, Chairman, President, CEO
Bob Daniels, EVP, International and Deepwater Exploration
Darrell Hollek, EVP, US Onshore Exploration and Production
Bob Gwin, EVP of Finance and CFO
Jim Kleckner, EVP, International and Deepwater Operations

Analysts
Evan Calio, Morgan Stanley
Doug Leggate, Bank of America Merrill Lynch
Brian Singer, Goldman Sachs
David Tameron, Wells Fargo
Bob Brackett, Sanford C. Bernstein
Subash Chandra, Guggenheim Securities.
Scott Hanold, RBC Capital Markets
John Herrlin, Societe Generale
Charles Meade, Johnson Rice
Ryan Todd, Deutsche Bank
Dave Kistler, Simmons & Company
Edward Westlake, Credit Suisse

Exhibit
388

Presentation

Operator: Good morning, and welcome to the third quarter 2015 Anadarko earnings conference call. (Operator Instructions). After today's presentation, there will be an opportunity to ask questions. (Operator Instructions). Please also note today's event is being recorded.

I would now like to turn the conference over to John Colglazier. Please go ahead, sir.

John Colglazier: Thank you, Rocco. Good morning, everyone. We're glad you could join us today for Anadarko's third quarter 2015 conference call. I'd like to remind you that today's presentation does include forward-looking statements and certain non-GAAP financial measures. We believe that our expectations are based on reasonable asumptions. However, a number of factors could cause results to differ materially from what we discuss today.

We encourage you to read our full disclosure on forward-looking statements and the GAAP reconciliations located on our website and attached to yesterday's earnings release. Additionally,

we have provided additional detail in our quarterly ops report on our website.

At this time, I'll turn the call over to Al Walker, and we'll open the lines in a few minutes for Q&A with Al and our executive team following his remarks. Al?

Al Walker: Thanks, John, and good morning. As we've said throughout the year in this period of lower commodity prices, our focus is on building and preserving value, rather than on growth. And we're accomplishing what we set out to do. I can't say enough about the efforts of our employees this year, the tremendous operational successes they've achieved and how these actions have made Anadarko a better company.

We're enhancing our wellhead margins by reducing costs and improving operating efficiencies. We've increased oil sales volumes by more than 42,000 barrels per day to date over 2014 on a divestiture-adjusted basis, and continue to improve our liquids product mix.

In addition to improving our cost structure by working with our service providers and vendors, we're also making permanent process enhancements and optimizing our operations in a manner that is sustainable over the longer term. Along these lines, I want to highlight a couple of assets that really illustrate how we are sustaining our business and improving it every day.

If you remember last quarter, we discussed the exceptional efficiency gains achieved in the Wattenberg Field by doubling the number of wells per rig line versus the prior year. Believe it or not, we're safely making further improvements sequentially by reducing cycle times during the quarter by almost 20% and cost per foot by almost 15%.

Since last year, our organization has further reduced our costs by nearly $70 per foot drilled on each well. That's a savings of almost $1 million per well as a result of our enhanced well bore design.

Plus, because of the work our Company has done, the Delaware Basin is gaining ground. The success we enjoy in the Wattenberg Field is one of the most attractive and economic plays in our onshore portfolio and one of the best in our industry. Even though we're not choosing to chase growth at this time on our 650,000 gross acre position, the work we're doing is laying the foundation for the future.

In our Wolfcamp oil play, this year alone, we've reduced our per-well cost by $4 million to $7.5 million with direct line of sight to another $1.5 to as much as $2 million per well and expect the savings at a time that we choose to pursue growth and migrate towards pad drilling across the field.

For the past several years, we focused on being financially disciplined, and we entered 2015 with the mindset of maintaining the strength of our balance sheet by aligning capital investments with anticipated cash inflows. This approach has served our stakeholders exceptionaly well in the current environment. The delta between our capital investments and discretionary cash flow totaled $730 million, which includes $405 million of West Capital. So we've covered the difference several times over by monetizing nearly $2 billion of assets this year.

In addition, we continue to demonstrate our commitment to financial discipline by lowering the high end of our 2015 capital guidance by an additional $100 million, as well as lowering our LOE guidance.

At this time, like many companies, we're evaluating 2016. At Anadarko, our program will be similar to our mindset in 2015, and that's investing within our cash inflows. This approach is expected to result in lower CapEx and sales volume that are relatively flat year-over-year on a divestiture-adjusted basis.

Given the challenging supply and demand fundamentals and continued uncertainty around sustainably higher oil prices, you can expect us to see continued investment in higher percentage, longer cycle opportunities, such as exploration, where we achieved some very encouraging early results in offshore Colombia, as well as success delineating our activities at Shenandoah and advancing our mega-projects like Heidelberg, where we've cleared all the major construction and installation hurdles are now on an accelerated timeline for first oil.

Consistent with our 2015 aproach to capital allocation, we'll continue to invest fewer dolars in short-cycle US onshore activities. This approach reflects our conviction that growth will not be rewarded in this environment, and focusing on preserving and building value is more aproprirate at this time.

Looking ahead, we'll remain focused on creating value by enhancing our wellhead margins and moderating our base decline, improving cost efficiencies, maintaining an active exploration program and pursuing ongoing monetizations like we have done in prior years. The value we're creating today will give us the foundation for future success. When we see value pursuing growth, we'll be prepared to accelerate activity.

So with that, why don't we open it up for questions?

Questions and Answers

Operator: Thank you. We will now begin the question-and-answer session. (Operator Instructions). Evan Calio, Morgan Stanley.

Evan Calio: Let me start off just following up on your evolving thoughts on the 2016 budget, given the commodity price deterioration and the deterioration or the lack of access in the MLP space since the last call. Can you provide color on commodity pricing scenarios? Is there a maximum amount spend and how does that relate to your thoughts on forward asset sales and accessing the MLP markets?

Al Walker: Let me start by just saying we don't have any better crystal ball that anybody else on what prices are going to be in 2016 and 2017, and our approach is plan for the worst and hope for the best. Consequently, we have a fairly low expectation, not much different than the forward curve, maybe even a little more pessimistic than that in terms of how we might plan for capital.

As it relates to asset sales, I think going back to January of this year when we talked about not pursuing growth maybe a little bit earlier than most, and that we'd continue to execute a plan that included portfolio management and sale of assets, we still believe that'll be something we'll do in 2016. And I think the comments that we continue to make around wanting to be cash neutral with our CapEx will hold the day. I think we've done a pretty darn good job of that since 2007 and I can't see 2016 being a different page in our playbook.

Evan Calio: So a similar size on an asset disposal program going forward is your thought within that, living within cash flow, inclusive of asset sales?

Al Walker: I'm making the comment that we'll live within cash. So if you look at this year and you think about my prepared comments and how I highlighted the fact that this year, we've exceeded what we believe to be our cash inflows with outflows, that speaks to the fact that we do think it's very important to make sure that we're financially disciplined, and that we continue to look for opportunities to sell assets where we think they're either non-core or the market sees the value in them greater than we do. I think I said we've done a pretty darn good job of that since 2007, so it's not just all of a sudden, we're waking up and trying to do that in 2016.

Evan Calio: Great, that makes sense. And a second question if I could -- any guidance on 2016 maintenance CapEx or spend to stay flat, which is likely lower due to efficiencies, DUC drawdowns as well as your offshore startups?

Al Walker: I think the number that we've been using recently is probably still an appropriate number and that's about $2.7 billion in terms of that maintenance number you're looking for. And that is still a function of lots of things that are asumptions in that, including commodity prices and service costs. So I'd call that a good place-holder number, but I don't think there's a lot of precision around it. I'm not sure anybody could give you a lot of precision at any time when there's as much volatility in the market as there is.

Evan Calio: That's fair. Lastly on -- congrats on the Shenandoah appraisal. Can you discuss how the results compare to predrill expectations or comments on the reservoir quality, and go-forward plans? I'll leave it at that, thanks.

Darrell Hollek: Yes, thanks, Evan, for the congratulations. The team did a really good on that and we're real pleased with it. We got 622 feet of pay. What we ended up doing was we tested up to the north with trying to find out where the basin edge was and the first well -- established where the basin edge was. Then we came in and drilled to the south with a side track and got the 622 feet of pay. It was all oil; we have no water in that.

The reservoir quality in the initial assessment looks pretty -- it looks comparable to everything else we found out there, so very good reservoir quality. We're still in the early stages of that evaluation. We're in the process of getting a core, so we just kicked off, and we're going to do a bypass core just right next to this well. And that's to establish the reservoir quality in the oil column, which will roll directly into our development planning.

So it's very important to get that core and we're just in the process of it. That's going to give us a

much better handle on all the fluid properties, all the reservoir properties, but we pushed the most on oil, down about 400 feet. As I mentioned, we [didn't] establish an oil-water contact here, so that tells us there's more down below us.

And we're looking at what the forward plan is after this bypass core as to what else we're going to need to turn over to the planning team for the development planning. But we're very encouraged with what we saw and it was well within the range of expectation of what we had put out there.

Evan Calio: Thanks, guys.

Operator: Doug Leggate, Bank of America.

(Cross-Talk)

Doug Leggate: I thought you were going to comment on my voice; I sound a little husky this morning. So guys, on the capital allocation for next year, so I get the living within cash flow. But given the very strong performance you seem to be having in the Delaware, how should we think about how you're allocating capital to your core plays? And could you maybe just touch on where you're not spending capital, what the implications are for potentially just the asset sales are likely for this quarter?

Al Walker: Doug, as you can appreciate, we, like all of our companies in our sector right now, are trying to decide how we want to allocate capital next year, looking into a very, at best, fuzzy picture of what that's going to look like. I think as you think about our Company, our two principal onshore assets in the DJ Basin and the Delaware Basin is where a majority, if not almost all of our onshore capital will be spent.

If you think about how we allocate capital from a short, intermediate and long, probably somewhere around the 40% allocation level will go into short and a large percentage of that 40% will go into those two assets plays as a percentage of whatever the budget turns out to be.

Doug Leggate: To Evan's point, would it be fair to think about asset monetization as basically funding the non-productive capital? Is that one of the levers you have?

Al Walker: It could. I think asset sales in any given year for us -- and certainly 2015 is a good example. I'm not sure we had a lot of people that agreed with us back in January when we made the comments we made then about not pursuing growth and continuing to be active with portfolio management, and that we'd sell properties in an environment that looked pretty challenging. And yet we did.

So I think as we think about how we want to recycle capital and reinvest it, there will be assets that we look at that we'd prefer to take and recycle that capital into things that have better trajectory around growth and returns.

Doug Leggate: Okay. Thank you. Just two quick follow-ups, if I may. I guess the first one is I

think yourself and Bob -- perhaps that (inaudible) the other way around -- Bob and yourself put the capital (inaudible) earlier this year by alluding to Anadarko possibly looking at acquisitions. I wonder if you could give us your thoughts on that?

And my final one is on Paon, just that comment on those additional blocks you got. Does that say anything about where you think the extent of the Paon discovery moves next, given that you added those two blocks in Cote D'Ivoire? I'll leave it there.

Al Walker: Okay. I hope you feel better; you do sound like you're not 100%.

Doug Leggate: [You're right].

Al Walker: And I'll ask Bob Daniels, if he would, to address your Paon question. On the M&A, I'll stay with the comment that we always make, and that is our objective every day is to be a better company, not necessarily a bigger company. But if, in an effort to get better, we have situations that would cause us to get bigger, we'll certainly evaluate those.

In the area of onshore that we have, I made comments just here a few minutes ago about where we want to see ourselves spending our capital, whether it's cash or cash flow. I think those are the areas of asset acquisitions that we'd focus on. And Bob, if you want to (inaudible) on?

Bob Daniels: Doug, on Paon, we picked up one block, not two. We ended up with the 527 block as a new block and that fit in between the CI-103 where Paon is located and the 520 and 529 blocks we already had acquired. So we have a contiguous 4-block area out there.

The reason we picked up 527 was twofold. One, it looked like there was a potential that the Paon accumulation could spill into 527, not in a huge way, but we certainly didn’t want to have somebody else get into our business there. And then we shot a 3D that covered the entire area earlier and 527 was part of that 3D, and when we looked at the prospectivity of 528, 529 and then the new 527, we could see that also came up onto the new block.

And so we went to the government and we were able to negotiate for 527 and put that into the portfolio. It makes for a better positon out there, a stronger position, that we control and so we have both the Paon appraisal work that's going to go on that says we're done in Colombia. And then we have exploratory drilling that we're planning in the 3 exploratory blocks, 27, 28, 29, probably starting next year.

We'll see how that all ends up with the budget issues, but right now, that's the plan. We like the area out there. the Paon is -- we're going to learn a lot from the DST that we're going to do out there with the #5 well and then we'll be looking at getting some exploratory wells drilled.

Doug Leggate: All right. Just a quick follow-up -- the 90% working interest, I'm assuming that's not your long-term plan.

Bob Daniels: No, we've got 90% working interest in the 3 exploratory blocks and where you just (inaudible) the data room, we're waiting for the 527 block to be finalized, so that we could then

put the whole package together. So those will be all put together as a package.

Doug Leggate: Great stuff. Thanks very much, everybody.

Operator: Brian Singer, Goldman Sachs.

Brian Singer: Can you talk to how your backlog of drilled and uncompleted wells in the oily plays, as well as the curtailed volumes in the gassy plays, play into your capital allocation for 2016? Should we expect these to be deployed to help you improve cash flow without drilling or are there some minimum drilling requirements to maintain efficiencies where you'd wait until price has improved more dramatically before bringing that backlog on?

Darrell Hollek: Brian, this is Darrell. If you look at what we're calling our IDUCs today, the intentionally deferred uncompleted wells, we've got a lot of flexibility around that. To date, we've got about 200 of these, largely in Wattenberg, but really in our big three assets, if you will, is where they all reside.

And I think you can look at that as flexibility as we go into 2016. We obviously have the option to stand up completion rigs here and our completion crews here in the fourth quarter, but with commodity being what it is, I'm not sure that's going to be our best move forward.

But I think if you look at 2016 for sure, as we look to pull back capital, these are going to be very efficient opportunities for us to maintain our volumes while spending less capital. So I think you can look at it as a huge lever for our 2016 program.

Brian Singer: That's great, thanks. And my follow-up is on the offshore. Can you characterize the cost structure you see now for development projects, both as you think about the rates of return from Shenandoah -- I know that's still well in the future, but also in Mozambique, what oil or LNG price do you need now versus, say, a year ago?

Darrell Hollek: We're seeing cost reductions across the board offshore. Obviously, the ultra-deepwater drillship market has come down significantly, but we're also seeing a lot of the services supported on the rig side as well -- wireline, pumping services, mud and cementing operations.

That being said though, they probably haven’t approached the commodity price reduction. So we're having to, when we look at our offshore developments, look at larger, more prolific reservoirs as Shenandoah is. It has a very high oil column and we'll be testing deliverability of these oil columns to see what type of flow rates we have. So we aren’t going to be able to offset the commodity prices completely, but what we'll look at are higher flow rate completions and try to work the cost structure down on the offshore marine development systems as well.

We've brought in new sixth-generation rigs and the initial results on those wells are very, very encouraging as far as reducing our cycle time to drill. So we're seeing some cost improvements that just not so much equate to service productions, but efficiencies in drill times. Some of our recent wells in Heidelberg have hit record costs for us of less than $100 million to drill. That's

not the completion cost, but drill cost.

Brian Singer: That's great; that's helpful. Anything in Mozambique update as part of that?

Darrell Hollek: The LNG markets are affected as the oil markets as well. I'd say this; as the Mozambique project progresses, we're hitting the market with procurement regarding the subsea equipment, the infrastructure, the offshore pipe water [lay] vessels to put everything in place for the offshore development.

And then the onshore development (inaudible) actually, we've already gone to FEED tender in those, and those costs are coming in better than the original cost that we had primarily due to the competition in the marketplace right now.

Al Walker: Brian, this is Al. I know you very likely know this and so I don't mean to repeat something I know you're well aware of, but just in case others are not, we believe that our cost of providing gas into a market there, if we're not the lowest-cost producer, we're certainly one of the lowest-cost producers in the world and how we bring that Mozambique LNG into the market at the back end of this decade. And I think that gives us a tremendous advantage in terms of how this project will move forward and why.

When we've been most recently in front of the utilities in Japan, why they see this as a very attractive place for offtake agreements in a market that's pretty crowded today. They just see the potential for multiple trains beyond the first two and recognize the benefit of being a foundational buyer.

Brian Singer: Thank you very much.

Operator: David Tameron, Wells Fargo.

David Tameron: Al, you talked a little bit about M&A. Can you talk about just the current bid-ask spread? I know -- I think it was a year ago when you came out and said it's a seller's market. Can you talk about how that's changed over the last 3 months, if you're seeing any movement there?

Al Walker: I think Bob Gwin and I can tackle that one with you. I'll give you my thoughts and he can give you his and if he disagrees with me, he can do that too.

I think like most people, we still see this extraordinarily large amount of private equity that's been raised and most people seem to gravitate around $100 billion as the number that's been raised and prepared to be committed to the sector over the next couple of years for investment if the right opportunities present themselves.

So unlike the public markets, where you have a little bit different dynamic at work, where we see ourselves today trying to bid on properties in markets where we had interest, we are being pretty consistently outbid, and most often times, we're being outbid by private equity-backed management teams.

And so I'm not sure I'd call that a seller's market quite like I did previously, but I'd say it's a healthy bid-ask in terms of exactly what's happening with properties when they come into the market and the receptivity they're getting.

Bob Gwin: David, this is Bob. I agree with Al. It's pretty clear that there are a number of management teams that -- the number I've heard most recently is maybe as many as 95 of them out there that have private equity backing, that haven't deployed capital yet in the market.

And the types of assets that we've been selling both earlier this year -- the three EOR, East Texas and CBN that we've announced -- were in a size range that's kind of a sweet spot for those types of buyers. And so I agree with Al, it's not the seller's market that it was earlier this year where we saw that on things we bid on, we might be getting outbid kind of to the tune of 2X, and had substantial success selling into it.

But we believe that there's still kind of a supply and demand fundamental around these kind of assets that in 2016, for the right assets and the ones that we're looking at that likely wouldn't receive funding in our portfolio over the next several years, that still have really nice return characteristics associated with them, we feel like it's going to be solid enough to be able to execute a program. And it's the reason it's part of our planning going into 2016.

David Tameron: Okay, that's helpful. Then Al, let me go a little philosophical on you. I hear what you're saying about returns and I know in theory, that's the right thing to do for a company and I know that's what the market should reward, but as you know over your career, growth has been rewarded, rather than returns.

How do you think about -- I know you've got to do what's right for Anadarko, but I'm just trying to balance those two in my head if I start thinking about -- 2015 is obviously done. Let's just look out to 2017, 2018. How do you think about that, because calling for a change in shareholder behaviors seems to be a difficult thing to do.

Al Walker: It's a fair question and a fair comment. I'd say historically, the observation has a lot of accuracy. My early read on, say, the first 9 or so months of this year is we've seen the buy side reward capital efficiency probably better than they historically have. As we move into potentially a longer period of lower prices, I think efficiency will still be something that gets rewarded and capital allocation around that efficiency will as well.

So I think as you look at companies like ourselves, and we're not unique, but those companies that have good wellhead margins, that are being able to improve those margins through the cost efficiencies like we've been talking about this morning, that are on top of that, good allocators of capital. I do believe in the -- I'll call it the intermediate term, that we probably will see the market, the buy side, reward companies that can achieve that.

And if you go back to the company that was created out of three companies in 2006 and since 2007, I think this Company and this management organization has done a really good job of allocating capital. That's one of the things that, while we've had anything but a stable market to

sell into or have had anything but a stable situation with respect to how we had to manage through two very difficult situations with [Turlocks] and Macondo, the allocation of capital became, I really believe, one of the things that allowed us to get through that; when you coupled it with what the employees were able to achieve with all of the allocation and decision-making and being able to move capital around and doing things in the field efficiently.

So Dave, I do believe we're probably entering into a period that maybe is a little different than the historical norm, and I think we saw a little bit of that in 2008 and 2009. But if you go back a couple more down cycles and look at it, your comment is fair. It's typically been a market that rewards growth and even in a period where you don't have wellhead margins, growth seems to be the mantra.

I'm not seeing as much of that personally today . I'd be interested to know if -- Bob, who works hand-and-glove with the capital markets as much as anybody in our organization, if you see it any different?

Bob Gwin: I don't see it differently in the current environment. You asked, I think, as far out, David, as, say, 2018, and one of the things that we're focused on with capital allocation, the reason we're focused, as Al mentioned earlier, in the onshore, the Wattenberg and the Delaware, is that these are assets that have tremendous intrinsic growth potential.

And so we remain in a position where we can dial up the rig count, dial up the completions fairly quickly, and even for a company our size, we feel we have the ability to deliver material growth combining that type of onshore growth with the mega-projects that we're bringing on in 2016 and on the back side of that, Mozambique.

So it's not a matter of we're ignoring growth; we're remaining ready for growth. We just think that the better allocation of capital today is to focus on building that longer term value and not accelerating growth, selling your best assets into a relatively lower margin environment.

Onshore in the US, everybody is going to drill their tier ones; they're going to focus on producing that tier one and then they're going to redeploy the capital into their next-best assets. And frankly, in our opinion, that's not the way to maximize value unless your shareholders are really telling you that growth matters more than value.

And what we've heard and what we continue to believe in, is that value preservation on the onshore and value building in the other parts of our portfolio, to be positioned for a more constructive commodity price environment is the right way to approach it today.

David Tameron: Okay. Thanks for the [thoughts]. I'll keep it at two. Thanks, guys.

Operator: Bob Brackett, Sanford C. Bernstein.

Bob Brackett: I had a question on the divestitures. How do you think about the minimum price you'd take for an asset? Is it strip pricing; is it what you're carrying the asset at? How do you think through that?

Bob Gwin: There's no real fundamental rule. Obviously, we have a pretty good view of what we think the asset is worth in a variety of different price environments. And we -- at some of those price environments, some of these assets theoretically could get funded in the future if the capital budget materially expands.

But you know it when you see it, when you see a bid that you start to look at what [forward] price expectations you'd need to achieve in order to have it attract capital. It makes it pretty straightforward to decide that it's better to go ahead and sell it today and obviously, you know that the tax implications matter. And whether or not we've got somewhere to go redeploy that capital matters.

It's not selling assets for the sake of selling them; but look at what we did this year. With EOR and dry gas in East Texas, EOR that hadn't free cash flows for us in a number of years; dry gas in East Texas where we hadn't run a rig in a number of years, and then coal-bed methane, which really requires a materially higher gas price to warrant capital in our portfolio. Selling those assets and redeploying an intermediate and long-cycle assets that build our inventory and our optionality and our growth for the future, to us, it's a clear positive trade.

And so with those types of assets, we weren't necessarily trying to achieve absolute top dollar; we were trying to achieve something that we felt was worth more in the portfolio and helped us to increase our NAV of the Company by making that trade of divesting today and reinvesting in the future. So it's multi-dimensional; it's asset-specific and it's use of proceeds around the assets that it's on an after-tax basis we receive.

Bob Brackett: Great. Thanks for that. A quick follow-up on Latin America; two thoughts there. one, any color on Colombia? The other, you had an offset operator in Guyana have a pretty sizeable discovery. Is there any read across to your Guyana activities?

Bob Daniels: This is Bob. On the Colombia, we had the Kronos well that we announced as the up-hole section last quarter as a discovery and then we went on down to the down-hole section. We did encounter some hydrocarbons there, non-commercial type things. We encountered a lot more sand than what we'd seen in the shallower section; good evidence of the thermogenic hydrocarbons in the lower section, but we still have a lot of work to do.

This is the southern-most well that we're probably going to drill in our acreage position, which is 16 million acres in the deepwater. We're drilling now 100 miles away on the same [Portay] area and then we've got the coal blocks up to the north that we're shooting seismic on.

So when you look at it, we're 300 miles to 350 miles from north to south out here. There's a huge area we have to evaluate and we need to take what we learn in the Kronos area, the Calasu well, what we're seeing on the seismic data and put it all together. But right now, we're still real excited about Colombia and look forward to drilling more wells there next year.

When you talk about Guyana, you talked about the Exxon discovery, offshore Guyana, it looks to be a nice discovery. I'd say the read-through to us is the petroleum system works out there and

it works in a fairly good, positive way. Our block is located to the north and west of theirs [outboard], and the main thing that we have going on in Guyana right now is if you remember several years ago, we were doing some drop-core work as part of our overall commitment out there, and the Venezuelan navy showed up and escorted our ship over to Venezuela.

So we're working with the government of Guyana, encouraging them to work with Venezuela to get this border issue settled. We felt like we were significantly inside the established border when this happened. And so we're waiting to see how that all plays out and we'll watch, of course, what's going on at the Exxon appraisal program to see how it spills over potentially into our block.

Bob Brackett: Great, thanks.

Operator: Subash Chandra, Guggenheim Securities.

Subash Chandra: Mozambique, back to the point on the breakeven costs, I think; what is that number that you're forecasting?

Al Walker: Subash, I'm not aware that we've ever given that number out and largely because we don't have final numbers from our FEED contractors, so I think that's probably a to-be-determined number for us. I think the only comments we've provided to date is that we believe that we can now build a 2-train, 12-million ton per annum facility for what we originally thought was a 2-train, 10-million ton per annum facility.

And our ability to continue to improve what will be costs associated with that development in this environment should go down. So consequently, I think those are the factors that you -- it's really difficult to tell you what a breakeven is and not one that today we could even begin to estimate.

Subash Chandra: Okay. Yes, okay, we'll wait on that then. The other thing is to interpret, I guess, the DUC commentary. Is it fair to interpret that, that the DUCs, the intentional DUCs, have a very high chance of being completed regardless of the commodity price environment? And that it would be offset by perhaps the rig count going lower between now and year-end? So the number of wells are still in line, but the DUCs, just because they're sort of pre-expensed, half pre-expensed or whatever, get the preferential completion schedule?

Darrell Hollek: Subash, this is Darrell. Yes, I would look at it that way. As we look at it today, we're pulling down some of our rig inventory now and we'll continue to do that in 2016. And it'll be largely to the benefit of completing these DUCs.

Bob Gwin: Yes, they're not really half pre-expensed though. The drilling cost is maybe 25% of the total well cost, and with still 75% of the capital associated with the completion. So there's not a lot -- there's not nearly as much sunk capital waiting on completion as you might otherwise expect.

Darrell Hollek: Yes, and I think one of the other big benefits that people don't recognize with

these DUCs, if you look back at some of the savings we've achieved this year in our completions, to have completed these wells earlier in the year when our cost structure was much higher would have actually hurt those economics. We really see some benefits now in really completing these wells a year later in some cases because it's going to continue to push our cost down, if you will, and improve our economics on these wells.

Subash Chandra: Okay. And the final one for me -- so the service companies are now pretty broadly complaining about that they're operating at sort of negative cash flows. Do you agree with that, and the takeaway being where -- at what price do you think the inflation kicks back in?

Bob Gwin: I'm not really sure that's a question for us, to be honest, Subash. You'd have to really talk to the service companies because it's not really something we monitor and track, and how they operate their business and what their breakeven cash costs are, we couldn't begin to estimate.

Subash Chandra: Yes, that's fair. If I could just put it another way, do you see any more deflation occurring?

Darrell Hollek: Again, this is Darrell. I will tell you we continue to see decreases in that price structure; I won't say as significant as what we saw earlier in the year, but there's still a lot of competition out there and a lot of pressure to get the cost down. And so we are seeing the benefit of that; we're continuing to.

Subash Chandra: Okay. Thank you.

Operator: Scott Hanold, RBC.

Scott Hanold: Just a quick follow-up question -- you obviously addressed the plan for the DUCs going into next year, but what would it take for you guys to actually reinvigorate drilling? I know it's obviously a bearish kind of outlook at this point in time is the right way to think of it, but what makes you change your mindset? What price level makes you feel (inaudible)?

Al Walker: Scott, I'll go back to the comment I made in January. Until we see service costs sync up to a price environment for the commodities that causes us to feel like growth can be achieved and sustained and then in turn, we'll be rewarded, we're not prepared to estimate what that is because we don't know exactly where the service costs are going to end up.

And certainly, we're no better than picking the volatility associated with oil or natural gas than anybody else. But when you think about oil, natural gas and natural gas liquids and the headwind that we, as an industry, are finding ourselves in with respect to all three of those, we're nowhere close to it today.

And the comment I made in January I think is still apropos, and we need to see a substantially different commodity price environment than we have today combined with a substantially different cost environment. Now, some of those costs have come in and we're starting to understand better what we think will be the right margin to go back to work in, a growth

environment that the investor would reward. But we don't see anything close to that in the near term with the type of commodity outlook you can see through the respective strips for how those commodities are traded.

Scott Hanold: Okay, appreciate that. And if you look at it as I think the industry entered into 2015, it looked like the service cost environment probably reflected a $90 oil environment. Where do you think that is today?

Al Walker: I think when we were at $90 -- and call it $4 -- the service costs that we've seen contract to date that created a margin at that time, we haven't seen that type of service cost contraction to get us back to a $90 and $4. If you're a successful efforts company, call it EBITDAX per BOE, and I'm not sure that we could, in fact, see that margin restore just through service costs alone.

It's going to take an improvement in the price per BOE, whether it's gas or oil or natural gas liquids that if you went through the arithmetic, I think you'd find that we're going to need to see a lot more from both of the principal commodities than we've got today. And then it becomes very basin-specific, then transportation costs associated with getting that to the market. So there's really not a generic answer from our perspective.

Scott Hanold: Okay, thanks. And one last one on Mozambique -- you discussed a little bit about that already on the call, but again, coming into this year, I think the idea was to sanction the project by year-end. Where do you see that occurring now and what are the implications on the CapEx that would have been allocated in 2016 to the project?

Al Walker: Nothing really new has developed that's caused us any concerns. I think we continue to believe that ultimately, this process is somewhat controlled in the hands of the government. We can do all that we can do and I think we're seeing the current administration working very hard in its first year to advance all the things contractually they need to advance. We've been very pleased with the way in which the Nyusi administration has addressed each of the things that we've brought before them.

It seems like there's good partner alignment and while we're the first to say it was a better price environment for LNG when oil was $100, you still have some benefits here by the comments I made earlier about being a low-cost producer that I think gives us an advantage with our off-take agreements with the principally East Asian buyers. So in general, it's still pretty good.

I think the benefit of what you've got with us is you've got a company, as we look out into 2016, that can be even less capital intensive with respect to maintaining our sales volumes in 2016 versus 2015, and still has the capital to invest in the intermediate and long-cycle things that we think creates a lot of value for investors long term. And I think that optionality and flexibility in our portfolio is really one of those things that we certainly think distinguishes us from others and I've heard that from investors as well. And then you just have to allocate the capital correctly between your opportunities.

Scott Hanold: Okay. Thank you.

Operator: John Herrlin, Societe Generale.

John Herrlin: Two quick ones for me -- with the Delaware, you bought some checker-boarded acreage. How hard is it to procure it these days, and also going forward, when prices normalize, how quickly would it take for you to get to a pad mode?

Al Walker: John, this is Al. We do have a checker-boarded position, as you correctly identified, and it is not an easy land situation to manage because it's very fractured in the Delaware Basin beyond the checker-boarding that we have already. And as we tried to block up in that area, it's really a difficult thing to do, and that's why making acquisitions where we think they're accretive and are attractive, help us in that blocking approach.

And I think the type of returns we'd want to see from the Delaware would need to start to approach what we've got today in the DJ in order to feel like going into a development mode created value for our shareholders. And we're not quite there, because we don't have the benefit of the mineral interests underneath the working interest in the Delaware like we do the DJ Basin.

And yet from everything we've seen -- and I'll ask Darrell to elaborate -- but from everything we're seeing, we're seeing really productive wells. That's why we took the EURs up. We believe once we go into pad drilling, we can drive down the cost further and I made reference to the fact that then get another $1.5 million to $2 million per well to be able to drive down once that works.

But it's really almost sustainability of a higher oil price than just getting to a higher oil price. You have to believe that once you get there, it's sustainable, and these pop-ups and pop-downs that we're seeing and the volatility associated with how oil's moving around is largely what's giving us a lot of pause and hesitation. So Darrell, please.

Darrell Hollek: Yes, I think the only thing I'd add to that is once we can get to more of a stable commodity price, if you will, the upside of Delaware just continues to get a whole lot better. It seems like every time we do a look-back on our existing wells, we're seeing additional EUR. So we're extremely encouraged there. We talk about approaching 1 million BOEs; in some cases we think we're well over 1 million. But as a whole, I think the important thing is, is across the entire acreage position, as we've continued to drill there, we're seeing the EURs move up.

So we're really encouraged. It's still early in the life. So we're hopeful that this will only continue to get better and so as we see commodity pick up, we're ready to go. I think getting into a pad drilling effort will be huge for us because we will see a lot of synergies like we have in our previous shale plays and so we're waiting for that day we can start standing up more rigs.

Al Walker: John, can I just add one more thing to that? As we think about the success we've had in the DJ Basin with our approach to the infrastructure there, and the way in which we want to manage our Midstream and evacuation risk, we're doing the same thing in the Delaware. And we probably actually have the benefit of having an even more aggressive approach to the Midstream than what we're trying to attempt with the Delaware simply because these Wolfcamp benches are

just really incredibly prolific at this point, as we understand them better.

And I know there are a lot of companies that always feel like they've got really good assets, but boy, I'll stack up the DJ and the Delaware Basin as an asset play in this environment with anything anybody's got in their portfolio. They're really resilient and they actually do have, to Darrell's point, tremendous running room when you're ready to go to growth.

John Herrlin: Great, thanks. My next one's on the deepwater. You've accelerated Heidelberg and you're only tying in three wells. Is this going to be the new mantra, not tie in all the wells, but just get enough to get cash flow up and going or what's the strategy there? And then lastly, in the Cote D'Ivoire, will you make an announcement in the first quarter once you run the interference test at Paon?

Jim Kleckner: This is Jim and I'll address the discussion on Heidelberg and then let Bob talk about the exploration in Cote D'Ivoire. In Heidelberg, the timing on the wells was really due to the drilling and the completion plans we had set. I wouldn't say that having three wells, partial well completion would be our mantra going forward. It's simply the timing. Our project team has made incredible progress here in the last, I'd say, 6 months.

The Gulf of Mexico has had difficult loop currents and they were successful in placing the [hull] in the top sides and the commissioning work ongoing for the top sides is in process. And as they've advanced that ahead of schedule, we've pulled the start date up a few months early. So it's just a timing issue on when the wells will be completed and then brought online across the facility.

John Herrlin: Thanks.

Jim Kleckner: And John, upon -- we'll announce the results, whatever quarter it's done. We probably won't even start that process until early in the new year or maybe very, very late December. So whether we get it done in the first quarter or the second quarter, we'll be releasing it once we have that information.

John Herrlin: Thank you.

Operator: Charles A. Meade, Johnson Rice.

Charles Meade: If we could go back to a comment you made in your prepared comments. You mentioned that you think in 2016, you foresee flat volumes versus 2015 on a divestiture-adjusted basis if I heard that correctly. Could you decompose that a bit by product and geography? And particularly, I'm thinking about one of the big pieces is the tailwind I think you're going to have from your Gulf of Mexico developments on the oil side.

Al Walker: Yes, you did reference the comment correctly and we do see ourselves being cash neutral to our CapEx as we go into next year on our preliminary [thoughts]. Now, we've not taken a plan yet to our board for approval, so those are very early ideas on our part. And you can anticipate, given that we haven't run a dry rig or a rig for dry gas in over 2 years, that our

percentage of oil continues to increase in our mix. You've seen that through the course of this year and you saw the increase year-over-year for the quarter of 24,000 barrels per day of greater oil. And I think you should anticipate oil will continue to be a bigger percentage of our overall mix in 2016 even if the capital on a year-over-year basis is likely down unless commodity prices do something that I don't anticipate.

Charles Meade: Got it. And any comments on geographies? In particular, it looks like US onshore oil is where we're seeing strength, although I know in Algeria we had that weather delayed tanker [lifting].

Al Walker: Yes, I think we'll probably be in a position, as we usually are in early March with our with our analyst conference, to be able to give you the granularity you're looking for once we have a budget approved by our board.

Charles Meade: Okay. Thank you on that, Al. And then perhaps dove-tailing to that, the cycle times in the Wattenberg, I have to say I'm not surprised that they're improving, but the magnitude is a little surprising, especially given that we're 9 months into a downturn. And I'm wondering if you could talk a bit more about what's going on there and what the prospects are for that to perhaps continue either in the Wattenberg or in other parts of your onshore portfolio.

Al Walker: The short answer is Darrel's really good.

Charles Meade: I had already assumed that.

Darrell Hollek: And let me give you the longer version then, Charles, but the redesign was probably the biggest thing we did out there. And so right now, we're working on a rate of penetration there in some of our non-productive time to continuously improve on what we're doing there on the drilling side.

I think the other part of that equation is early on, as we changed some of this design, we didn't have it going across all of our rig fleet and today, we do. And so you're seeing the benefit of that across the whole fleet out there and so that's a part of that improvement as well.

As far as going forward, I think the opportunity probably rests with both our completions and even some of the facility costs that we have in front of us. We're working on a central oil stabilizer system right now, which essentially allows us to put less equipment on some of our well sites today. So I see that there's going to be a future opportunity to get that DC&E cost down in the Wattenberg.

Charles Meade: That's helpful, Darrell. Thanks for your comments.

Darrell Hollek: Okay.

Operator: Ryan Todd, Deutsche Bank.

Ryan Todd: Maybe if I could follow up, you've discussed it a little bit in terms of the Permian,

but can you talk a bit about how you're managing both the resource delineation and the infrastructure buildout during this -- I guess we can consider it the downtime and how that will position you for acceleration when the commodity allows it?

Darrell Hollek: Again, this is Darrell. Right now, we're not in a development mode, so we're continuously -- you got a couple things going on. We're holding acreage in some cases where the leases require it, but in other cases, we're still testing. Again, there's multiple benches out here, although we generally talk about one bench within the Wolfcamp A, but there's other benches here to be tested along with the completion styles we're using.

And so we're varying both the water and sand components here just to better understand how do you get these EURs up. And so part of the discussion earlier on increased EURs, we do think we're better understanding what completions are working out here. And so again, it's not a hodge-podge, but we're going across a huge acreage position to better understand what we have so that when the commodity does turn and we go into development mode, we'll probably start where a large part of our infrastructure is, but we'll know where some of the better places are. But as we recognize it right now, really across the entire acreage, we really think most of this is all tier one, and so we're pretty excited about all the results we're getting in.

But to another point, on the infrastructure side, we continue to build that out. Although we've slowed down some of our drilling activities, we have not slowed down our buildout of the infrastructure.

Ryan Todd: Great. So I'd assume that as the commodity turns, you should have plenty of running room with few, if any, bottlenecks on the infrastructure side to be able to ramp materially. Is that --

Darrell Hollek: No, I think that is fair. Once things go into a pad drilling format, if you will, we'll likely start very near the infrastructure that's out there so that we ought to be up and running and see the benefits on the production side pretty quickly.

Ryan Todd: Great, thanks. And then maybe if I could do one quick follow-up, and you may not have anything to add on Shenandoah, but post the recent appraisal well, any additional thoughts on resource range there at Shenandoah? And on timing of the FID, maybe it's too early to tell without seeing the core, but do you know -- do you have an idea whether you think you need one more appraisal well prior to FID or is this all that you'll need at this point?

Bob Daniels: Yes, this is Bob, Ryan. On the resource range, we're right in where we thought. We always do a probabilistic resource range; we're still in that range with the results of the well. We still haven't established a water contact over here, so you still have uncertainties associated with that.

As to FID and whether or not we need additional wells, I think those discussions are ongoing, but I think we also need to get all the data in and really incorporate that into our thinking as to, okay, what do we have here for sure; what do we now have uncertainties around; and what does that mean for additional activities? So it's too early to say on whether there needs to be an

additional well. And the FID would come after that, kind of a -- or the pre-development work leading to an FID is ongoing, but that would come after we've got all the data that we need.

Ryan Todd: Great, thanks a lot. I'll leave it there.

Operator: Dave Kistler, Simmons & Company.

David Kistler: Looking at the 2015 CapEx guidance and thinking about this next quarter, the last couple of quarters, you've come in below the low end of guidance. You talk about your DUC inventory that you have. Can you kind of help frame up where the CapEx is relative to your thoughts on DUCs at year-end and whether that's factored into the CapEx number, and likewise, how that looks on the production side?

Al Walker: Yes, Dave, we always give a risked operational profile for our objectives here. And what we've done for the fourth quarter, we've included in our capital guidance the flexibility to add the additional completion crews to start working down the DUCs as indicated in the table in our ops report and the volumes reflect status quo. So it's the -- we've covered ourselves both ways and I think you'll be pleased with the outcome.

David Kistler: Okay, appreciate that; so conservative in nature there. One of the comments you made on maintenance CapEx, I just want to tie that up a little bit. Keeping it kind of the same at $2.7 billion, but you're seeing better performance in terms of base declines. Looks like costs continue to come down slightly and efficiencies continue to go up. I would suspect that would buy us that number a little lower. Am I getting ahead of myself? Is there something else that would be keeping that flat versus the improvement we've seen?

Al Walker: No, Dave. I think you're seeing it correctly.

David Kistler: Okay, appreciate that. And then just finally on the base decline part of things, can you talk a bit about what the big drivers of those improvements have been and how you see that moving forward?

Darrell Hollek: You're talking about on the volume side in some of our big assets?

David Kistler: Exactly.

Darrell Hollek: Yes, right now, I'd say there's upside in looking forward because again, with the EUR improvement especially in Delaware, that should just give us upside going forward. And these are some of the results we're seeing now, and so as we continue to do these look-backs, hopefully we've got additional upside to that.

But again, remember, Delaware is relatively new and we're drilling this thing across the field, so we're pretty encouraged. So I think there's going to be a lot of little things out there to help us, so there's probably nothing I can point to specifically.

David Kistler: Okay, appreciate the color. Thanks so much, guys.

Operator: Edward Westlake, Credit Suisse.

Edward Westlake: I'll ask 10 questions; so just 2 very short ones. Spacing in the Wattenberg, I know you were doing tests; just an update there, and then spacing in the Delaware, I guess it's still early. You've got the Wolfcamp and you've got the Bone Springs. Obviously, there are other sections, but just maybe just a reminder of what spacing assumptions you're using today and where you see those going.

Darrell Hollek: Yes, this is Darrell. I would start with Wattenberg. We were at a -- between the Codell and Niobrara, we were 12 wells to 14 wells per section. Now, our norm is more 16, but I can tell you, we're looking at some tests this coming year from 20 to 30 wells per section, and we'll see what the results there are. But we're feeling pretty good that we probably, from a section standpoint, we think there's more to be recovered. As we continue to get our well costs down, we think there's more opportunity to increase that density, and so we're feeling pretty good about that we'll end up adding to that as opposed to where we are today.

If you look at Delaware, we're probably on 600-foot spacings based on what we know today, but I continue to make the point, this is early. So the more oil we see in these sections and that we can recover, that too may be increased, and a lot of that's going to just be driven by our drilling and completion costs. So as we get those costs down economically, we probably can afford to put more in a section if we're seeing those recoveries go up. So it's a little earlier there, but Wattenberg for sure, we're seeing that density go up right now.

Edward Westlake: And then just on exploration, the very final question, you've laid out a lot of work that you have to do on your existing discoveries. But in terms of wildcats next year, maybe just talk through the main ones that still get into the program.

Bob Daniels: Yes, we haven't finalized the plans for next year, but there will be several in the Gulf of Mexico. We'll probably have wildcats in Colombia and also over in Cote D'Ivoire and beyond that, we're still working the planning.

Edward Westlake: Okay. Thanks very much. I look forward to the update.

Operator: This concludes our question-and-answer session. I'd like to turn the conference back over to Mr. Colglazier and the rest of the team for any final remarks.

Al Walker: This is Al. Let me just say we all recognize that (inaudible) are challenging times, not just for companies, but for investors and for the broader investment community. And we really appreciate the support we're seeing from investors and appreciate the support we're seeing from analysts that follow us. You guys do a great job; thank you. I know it's difficult right now to do your job; it's difficult to do our job.

But I'll just leave you with this. You can anticipate that our employees will go to work every day working as hard as they can to create as much value as they can, given the market conditions that we're in. And I think what we've achieved so far this year reflects that determination and hard

work and you have our pledge as employees at Anadarko that we will come to work every day trying to create as much value as we can during a very challenging environment.

So with that, I hope everybody has a good day and a good week and thank you for joining us.

Operator: And thank you, sir. Today's conference has now concluded and we thank you all for attending today's presentation. You may now disconnect your lines.